Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

April 22, 2010

FILED
2010 APR 22 P 4:08
PUBLIC UTILITIES COMMISSION

Dean K. Matsuura
Manager
Regulatory Affairs

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Subject: Docket No. 2008-0273
Feed-In Tariffs Investigation
Hawaiian Electric Companies' Responses to Information Requests

Pursuant to the Commission's October 29, 2009 Order Setting Schedule in the above subject proceeding, attached are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited's (collectively, the "Hawaiian Electric Companies") responses to information requests from the following Parties:

- The Department of Business, Economic Development, and Tourism[1]
- Hawaii Renewable Energy Alliance
- The Solar Alliance and Hawaii Solar Energy Association
- Sopogy, Inc.
- Zero Emissions Leasing LLC

In addition, included in an envelope is a compact disc containing Excel files, which contain formulas, calculations and workpapers in response to DBEDT/HECO-IR-3 and ZE-IR-116.

Very truly yours,

Attachments

c: Distribution List

[1] DBEDT's information requests were submitted informally (not filed with the Commission) on April 8, 2010.

Response to

Department of Business, Economic Development, and Tourism's

Information Requests

DBEDT/HECO-IR-1
Ref.: Schedule FIT TIER 3, Section C – Seller Participation.
Why does participation under this Schedule FIT require "the concurrence of the Independent Observers"?

HECO Companies' Response:

In order for Sellers to participate in the FIT program, they must have their project applications approved for placement in the Queue. The HECO Companies' proposed queuing procedures currently call for the concurrence of the Independent Observer when determining and setting the Queue.

<u>DBEDT/HECO-IR-2</u>

Ref.: Schedule FIT TIER 3, Section C – Seller Participation.

a) Please explain how and who will determine the "queue capacity".
b) Please explain whether the "queue capacity" will need PUC approval and how HECO plans to seek such PUC approval?
c) Will the Parties in this docket be able to review and comment on the "queue capacity before it is filed for PUC approval?

<u>HECO Companies' Response:</u>

a) The capacity allocated for the respective Tier releases will be determined by the HECO Companies. Factors that will be considered include, but may not necessarily be limited to, the amount of targeted capacity for the FIT program determined by the Commission, input from HECO's System Operations, Operations and Maintenance, and Renewable Integration Planning groups, input from the Reliability Standards Working Group, and consultation with the FIT parties and the Independent Observer.

b) HECO intends to allow the Commission the opportunity to provide its approval or other guidance for each release of Tier capacity. Prior to the release of each Tier, HECO will submit its proposal to the Commission along with a report to be filed by the Independent Observer. The Independent Observer's report will provide a recommendation to the Commission on HECO's proposal.

c) HECO proposes to seek input from the FIT parties and the Independent Observer prior to any submission to the Commission of a queue capacity proposal. It is anticipated that the FIT parties would also have an opportunity to submit comments to the Commission after any proposal by HECO is submitted to the Commission.

DBEDT/HECO-IR-3

Ref.: Section G – Purchase of Renewable Energy Delivered by Seller to Company.
Please provide the workpapers used to develop the proposed FIT Energy Payment Rate for each renewable generator type and size provided in G(1) and G(2) of the referenced section. Please include all assumptions and data sources used.

HECO Companies Response:

The Excel workbooks and data sources used to develop the FIT Energy Payments Rates have been furnished to the interveners. An email from Rod Aoki to the parties on March 10, 2010 at 5:24 pm contains the workbooks for each technology with specific scenario assumptions. (See attached files for the Excel workbooks.) The assumed data sources are outlined in detail in the PowerPoint presentation delivered to the parties at the March 10, 2010 Workshop on Tier 3 resources (see attachment 1). In addition, Marisa Chun sent an email to the parties on March 25, 2010 at 4:50 pm answering many of DBEDT's clarifying questions on this topic (see attachment 2).

Hawaiian Electric Company, Inc.

Feed-in Tariff Stakeholder Workshop

March 10, 2010

HEI

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

Hawaiian Electric Company, Inc.

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

Methodology

1. Reviewed installed Hawaii projects where available
2. Benchmarked mainland cost of generation for all Tier 3 technologies
   - Used public cost of generation sources, manufacturer quotes, discussions with developers
   - Included Hawaii premium for any freight, labor and land cost increases
3. Created project scenarios to get a inclusive range of LCOE estimates by technology
4. Used key inputs to develop additional sensitivity analysis to inform decision making

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

LCOE Model

- Black & Veatch model
  - Levelized Cost of Energy (LCOE) model
  - Developed for the Renewable Energy Transmission Initiative (RETI)
  - Vetted in a stakeholder process
  - The model can be found on the RETI website under Phase 1B Draft Report: http://www.energy.ca.gov/reti/documents/index.html
- Upgrades to make model HI specific
  - HI state tax credit
  - Insurance
  - Land cost
  - Excise tax
  - Production degradation
  - Tax rates

HEI

Hawaiian Electric Company, Inc.

Construction Finance Update – Tier 3

- Construction financing
  - Added to Capex using simple construction financing module incorporated into DCF model
- Construction timeframes (developer feedback requested)
  - PV – 4-8 months
  - Wind – 4-12 months
  - In-Line Hydro – 6-12 months
  - CSP – 6-12 months

HEI

Hawaiian Electric Company, Inc.

Construction Financing Module

PV construction module – 6 months

CONSTRUCTION FINANCING SCHEDULE

Month	% of Total Capital Cost	Equity Drawdown	Loan Drawdown	Cum Loan Drawdown	Construction Loan Beg. Balance	Additions	Interest	End Balance	Avg. Balance
							11.0%		
1	16.67%	2,708,333	1,458,333	1,458,333		1,458,333	6,714.8	1,465,048	732,524
2	16.67%	2,708,333	1,458,333	2,916,667	1,465,048	1,458,333	20,206.2	2,943,588	2,204,318
3	16.67%	2,708,333	1,458,333	4,375,000	2,943,588	1,458,333	33,821.9	4,435,743	3,689,665
4	16.67%	2,708,333	1,458,333	5,833,333	4,435,743	1,458,333	47,563.0	5,941,639	5,188,691
5	16.67%	2,708,333	1,458,333	7,291,667	5,941,639	1,458,333	61,430.6	7,461,403	6,701,521
6	16.67%	2,708,333	1,458,333	8,750,000	7,461,403	1,458,333	75,425.9	8,995,163	8,228,283
	100.0%	16,250,000	8,750,000				245,163		
Deferred interest as % of Total Capital Cost							0.981%		
Loan Amount excluding Capitalized Interest			8,750,000						
Equity funding during construction			16,250,000						
Capitalized interest			245,163						
Total capital cost including interest during constr			25,245,163						

HEI

DBEDT/HECO-IR-3
DOCKET NO. 2008-0273
ATTACHMENT 1
PAGE 8 OF 45

Hawaiian Electric Company, Inc.

B&V Transparent DCF Model

Cost of Generation Calculator

PV Tier 3 Project - COMMERCIAL

All inputs are in blue.

Technology Assumptions	
Project Capacity (MW)	2.5
Capital Cost before construction financing ($/kW)	$4,866
Capital Cost incl construction financing ($/kW)	$4,914
Fixed O&M ($/kW)	$18.0
Fixed O&M Escalation	2.5%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	0.0%
Insurance (% CapEx/year)	0.50%
Fuel Cost ($/MBtu)	$0
Fuel Cost Escalation	0.0%
Land ($/year)	$ 125,000
Land escalator (%/year, added every 5 years)	3%
Heat Rate (Btu/kWh)	0
Production Degradation (%/year)	0.75%
Capacity Factor	16.7%

Financial/Economic Asumptions	
Debt Percentage	35%
Debt Rate	9.0%
Debt Term (years)	20
Construction Debt Percentage	35%
Construction Loan Rate	11.0%
Construction Period (months)	6
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
Cost of Generation Escalation	0.0%
Federal Tax Rate (marginal)	35.000%
State Tax Rate (effective)	6.015%
State Excise Tax Rate (wholesa	0.500%
Cost of Equity	11%
Discount Rate	9%

Incentives		Cap
PTC ($/MWh)	$0	
PTC Escalation	0.0%	
PTC Term (years)	0	
ITC	30.0%	
State Tax Credit	35.0%	$ 500,000
No. of Systems (inverters)	40	

Outputs	
NPV for Equity Return	$0
Levelized Cost of Generation	$193.90

Year		1	2	3	4	5	6	7	8	9	10
Annual Generation (MWh)		3,656.3	3,628.8	3,601.6	3,574.6	3,547.8	3,521.2	3,494.8	3,468.6	3,442.5	3,416.7
Cost of Generation ($/mWh)		$193.90	$193.90	$193.90	$193.90	$193.90	$193.90	$193.90	$193 90	$193.90	$193.90
Operating Revenues		$708,960	$703,643	$698,366	$693,128	$687,930	$682,770	$677,650	$672,567	$667,523	$662,516
Fixed O&M		$45,000	$46,125	$47,278	$48,460	$49,672	$50,913	$52,186	$53,491	$54,828	$56,199
Variable O&M		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Insurance		$61,421	$62,957	$64,531	$66,144	$67,798	$69,493	$71,230	$73,011	$74,836	$76,707
Land Cost		$125,000	$125,000	$125,000	$125,000	$125,000	$144,909	$144,909	$144,909	$144,909	$144,909
Fuel Cost		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Excise Tax		$3,545	$3,518	$3,492	$3,466	$3,440	$3,414	$3,388	$3,363	$3,338	$3,313
Operating Expenses		$234,966	$237,600	$240,301	$243,070	$245,909	$268,729	$271,714	$274,774	$277,911	$281,128
Interest Payment		$386,955	$379,392	$371,147	$362,161	$352,366	$341,689	$330,052	$317,367	$303,540	$288,469
Principal Payment	$4,299,504	$84,040	$91,604	$99,848	$108,834	$118,630	$129,306	$140,944	$153,629	$167,455	$182,526
Debt Service		$470,995	$470,995	$470,995	$470,995	$470,995	$470,995	$470,995	$470,995	$470,995	$470,995
Tax Depreciation - State		$2,456,859	$3,930,975	$2,358,585	$1,415,151	$1,415,151	$707,575	$0	$0	$0	$0
Taxable Income - State		$1,929,683	($3,844,323)	($2,271,667)	($1,327,254)	($1,325,498)	($835,224)	$75,884	$80,427	$86,072	$92,920
State Income Tax (benefit)		$116,070	($231,236)	($136,641)	($79,834)	($79,729)	($38,209)	$4,564	$4,838	$5,177	$5,589
Tax Depreciation - Fed'l		$2,088,330	$3,341,329	$2,004,797	$1,202,878	$1,202,878	$601,439	$0	$0	$0	$0
Taxable Income - Fed'l		$2,182,142	($3,023,441)	($1,781,239)	($1,035,147)	($1,033,495)	($490,878)	$71,320	$75,589	$80,894	$87,330
Federal Income Tax (benefit)		$763,750	($1,058,204)	($623,434)	($362,301)	($361,723)	($171,808)	$24,962	$26,456	$28,313	$30,566
PTC		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Federal ITC		$3,685,289									
State Tax Credit		$4,299,504									
Net Taxes (due)		$7,104,972	$1,289,440	$760,074	$442,136	$441,452	$210,016	($29,526)	($31,294)	($33,490)	($36,155)
Net Cash Flow	(7,984,792)	7,107,971	1,284,488	747,144	421,198	412,477	153,062	(94,586)	(104,496)	(114,874)	(125,761)

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

Interconnection Costs

Interconnection Costs					
1 MW		2.5 MW		5 MW	
Item	Cost	Item	Cost	Item	Cost
Interconnection Requirement Study	$ 25,000	Interconnection Requirement Study	$ 35,000	Interconnection Requirement Study	$ 75,000
SCADA and Direct Transfer Trip	$ 500,000	SCADA and Direct Transfer Trip	$ 500,000	SCADA and Direct Transfer Trip	$ 500,000
		12 kV line extension - 1,000 ft.	$ 100,000	46 kV line extension - 1,500 ft.	$ 150,000
		Transformer	$ 80,000	Transformers	$ 525,000
Total:	**$ 525,000**	**Total:**	**$ 715,000**	**Total:**	**$ 1,250,000**

* 2.5 MW Transformer: 2,500 kva, 12kV - 480V distribution transformer and associated breaker, protective relays, etc.

** 5 MW Transformers: 5,000 kva, 46 kV - 12 kV substation transformer and five 1,000 kva, 12 kV - 480V transformers with associated breakers, protective relays, etc.

HEI

Hawaiian Electric Company, Inc.

Land Costs

- Range of $5,000 - $15,000/acre/year in lease costs for PV and CSP
- HECO modeled $10,000/acre/year for all project scenarios
  - The lease cost is escalated at 3%/year and increased every five years
- Wind & Hydro projects are assumed to have a revenue lease structure (2-4% of revenue)

Example Lease Escalation - PV/CSP	
Years	*Lease*
1 - 5	$ 10,000
6 - 10	$ 11,593
11 - 15	$ 13,493
16 - 20	$ 15,580

HEI

Hawaiian Electric Company, Inc.

Financing Benchmarks

	Range		Input
Equity	**Rate:**	10 – 15%	11%
Permanent debt	**Rate:** **Tenor:** **Percentage:**	8 – 10% 15 – 20 yrs 30 – 40%	9% 20 yrs 35%
Construction debt	**Rate:** **Term:**	10 – 12% 4 mo – 1 yr	11% varies

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

PV Benchmarking

PV Benchmarking			
Key Inputs		**Tier 3**	**Source**
Modules	$/watt dc	$1.60 - $2.00	Manufacturer quotes
Inverters	$/watt dc	$0.30 - $0.40	Manufacturer quotes
Interconnection	$/watt dc	$0.25 - $0.53	Manufacturer/HECO IC
Permitting	$/watt dc	$0.02 - $0.08	Planning Solutions
Balance of System (fixed)	$/watt dc	$2.10 - $2.70	Developer quotes
Balance of System (tracker)	$/watt dc	$2.50 - $3.10	Developer quotes
Installed Costs (fixed)	**$/watt dc**	**$4.27 - $5.70**	
Installed Costs (tracker)	**$/watt dc**	**$4.67 - $6.10**	
O&M	$/kW/year	$17 - $22	Independent Engineers
Insurance	% CapEx/year	0.45% - 0.55%	Insurance quotes
Degradation	%/year	0.5% - 1.0%	Independent Engineers
Land Cost	$/acre/year	$5,000 - $15,000	Land Quotes
Capacity Factor (fixed)	% (kWh/kW dc)	16% - 18%	PV Watts and SAM
Capacity Factor (tracker)	% (kWh/kW dc)	21% - 23%	PV Watts and SAM

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

HEI

Hawaiian Electric Company, Inc.

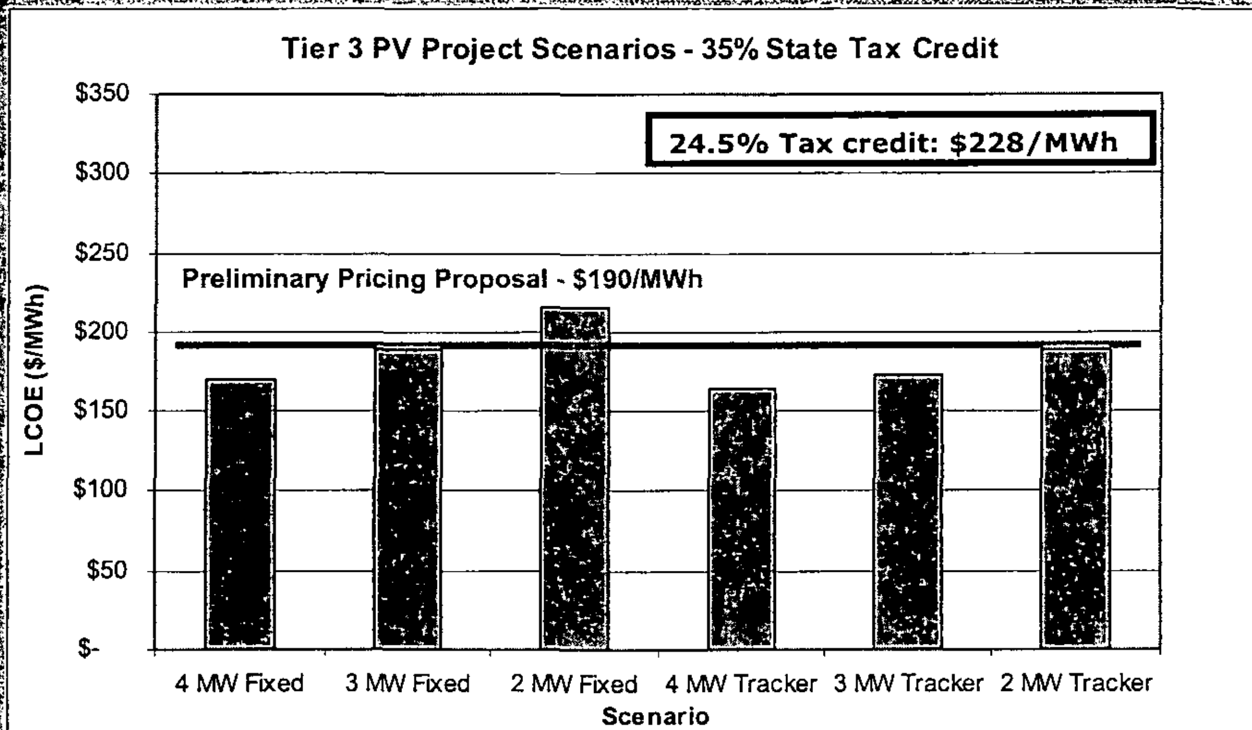
Permitting Costs – PV

Low	Medium	High
$10,000	$30,000	$75,000
▪ < 1 acre of land disturbance ▪ Private property ▪ In the State Urban, Rural, or Agricultural District ▪ Does not require disturbance of high-value habitat ▪ Served by existing roads and transmission	▪ Envir. assessment is needed ▪ No "substantial" land disturbance involved ▪ No cultural impact assessment ▪ Construction will not entail noise or traffic that could require special studies	▪ > 1 acre disturbed (requires a NOI-C be filed with the State Dept. of Health) ▪ Preparation of a Chapter 343 Environmental Assessment ▪ Moderate amount of other work needed

HEI

Preliminary PV Scenarios

Hawaiian Electric Company, Inc.



Key Inputs	4 MW Fixed	3 MW Fixed	2 MW Fixed	4 MW Tracker	3 MW Tracker	2 MW Tracker
Size (kW)	4,000	3,000	2,000	4,000	3,000	2,000
Capacity Factor (%)	17.3%	16.7%	16.0%	22.7%	21.9%	21.0%
Installed Cost ($/W)	$ 4.33	$ 4.66	$ 5.20	$ 4.73	$ 5.06	$ 5.60
LCOE ($/MWh)	$ 170	$ 188	$ 215	$ 164	$ 173	$ 188

HEI

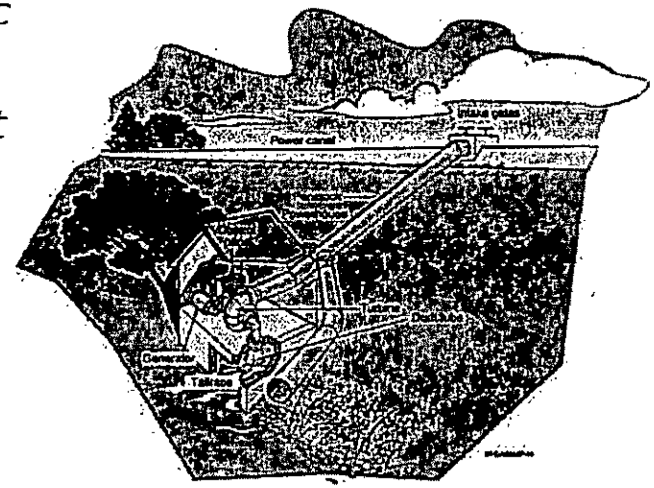
Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

Hawaiian Electric Company, Inc.

In-line Hydro Definition

Definition: *"in-line" hydroelectric generation is hydroelectric generation that utilizes energy from a water pipeline system that is designed primarily to serve another functional purpose where a section of pipeline is replaced with a turbine-generator section. In-line hydroelectric generation does not include (a) pumped storage hydroelectric generation, (b) run of the river hydroelectric generation or (c) any system using the energy from water from a new (after January 1, 2009) diversion from any river or stream.*



In Conduit Hydroelectric Schematic

Source: INEL

HEI

DBEDT/HECO-IR-3
DOCKET NO. 2008-0273
ATTACHMENT 1
PAGE 19 OF 45

Hawaiian Electric Company, Inc.

Hydro Benchmarking Study

Key Inputs		Tier 3	
Capacity Factor	%	10%-90%	2002 HI Hydro Generation Report; KEMA CEC COGS
Turbine-generator	$/kW	$950-$3170	75% of KEMA CEC COGS capital cost assumed to be turbine-generator. Hawaii freight & excise tax of 9.72% assumed
Construction & Installation	$/kW	$430-$1440	25% of KEMA CEC COGS capital costs assumed to be construction & installation. HI premium of 50% for labor and materials assumed
Permitting	$/kW	$10-$60	Hawaii specific estimates from Perry White, Planning Solutions
Interconnection	$/kW	$250-$525	Low estimate $160 for a 5MW system and high estimate of $525 for a 1MW system on a $/kW basis
Total Installed	**$/kW**	**$1650-$7600**	KEMA 2009 COGS ($1150-$3850); INL Hydro Database for HI ($1300-$4300); high end defined by installed project review
Insurance cost	% CapEx per year	0.45%-0.55%	Assumed same as PV
O&M	$/kW	$12-$105	KEMA 2009 COGS
Land	% revenue	2-4%	Assumed lease: HI Hydro report 2002

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

HEI

Hawaiian Electric Company, Inc.

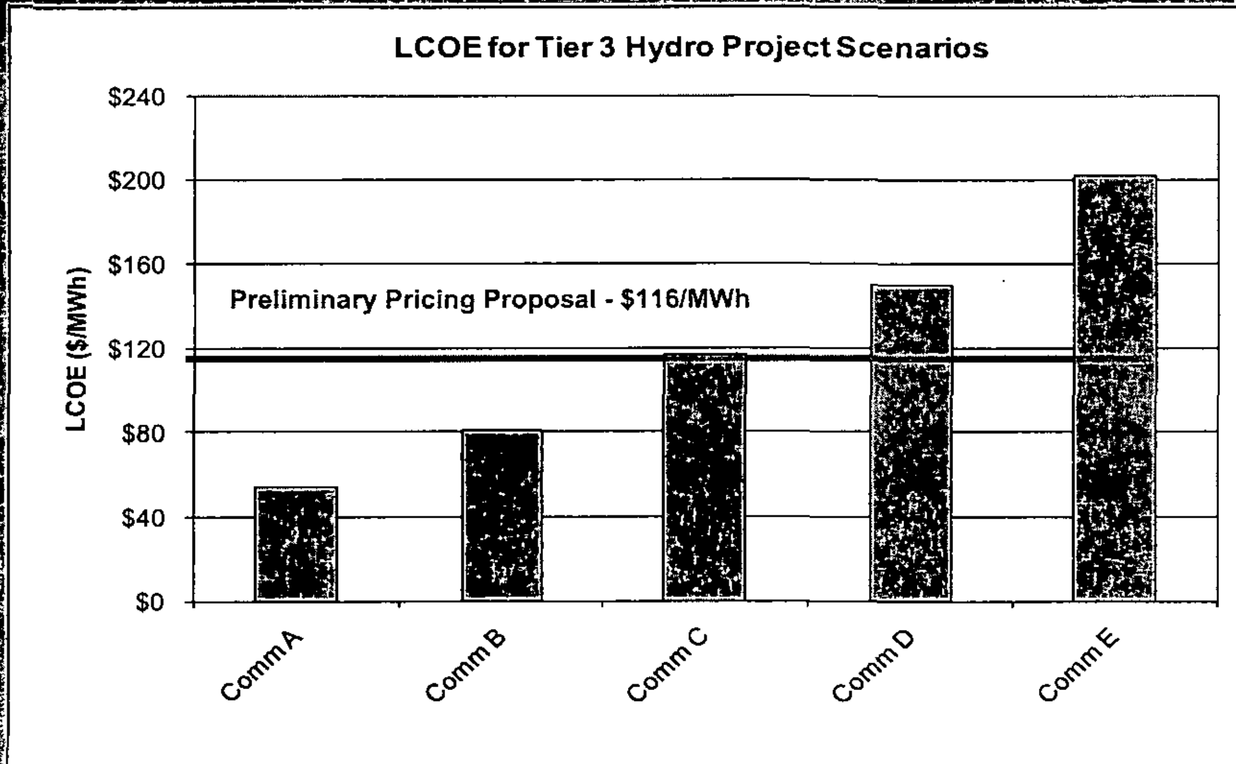
Permitting Costs – In-Line Hydro

Low	Medium	High
$2,500	$15,000	$30,000
▪ Assemble a conceptual plan ▪ Ensure that permits are not needed ▪ Obtain letter to confirm no approvals are needed	▪Departmental (rather than a Board) permit ▪ Exempt from the req. for a Chapter 343 environmental assessment or EIS	▪ Chapter 343 envir. assessment and Conservation District Use Permits are needed ▪ No extensive biological or cultural impact surveys

HEI

Hawaiian Electric Company, Inc.

Preliminary Hydro Scenarios



Key Inputs	A	B	C	D	E
Capacity Factor (%)	50%	50%	50%	50%	50%
Installed Cost ($/kW)	$ 1,610	$ 2,694	$ 4,149	$ 5,500	$ 7,585
O&M ($/kW-yr)	$50	$50	$50	$50	$50
LCOE	$54	$81	$117	$150	$202

HEI

Hawaiian Electric Company, Inc.

Hydro Pricing Issues for Discussion

- Resource availability
  - Project siting - large enough pipes to support 5MW projects?
- No HI specific installed costs within range
  - Assuming low end of installed cost range from Tier 2 because of economies of scale
- Should Hydro be included in Tier 3?

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

CSP Project Overview

Dish	Type	Year	Capacity (kW)	Capital Cost ($/kW)	Note	Source
Stirling Energy System	Commercial	2008	25	*9,000*	Cost of single 25kw dish	*News*
Stirling Energy System	Commercial	2004	1,000	6,000	Cost of 25kW dishes for 1MW plant	CEC
Infinia	Commercial	2008	1,000	*6,667*	Cost of 3kW dishes for 1MW plant	*News*
Navigant Consulting	Estimate	2006	25	8,000	Estimate without scale up	Navigant Consulting
Trough	**Type**		**Capacity (kW)**	**Capital Cost ($/kW)**	**Note**	**Source**
Navigant Consulting	Estimate	2007	15,000	3,900	Estimate. No storage.	Navigant Consulting
Black & Veatch	Range	2008		3600-4700	B&V gives 3,600-4,700 cost/kw	B&V Consulting
Black & Veatch- AZ roadmap	Estimate	2007	100,000	4,200	Wet-cooled solar trough plant	B&V Consulting
NREL- San Diego	Estimate	2005	100,000	3,246	Estimate for 2007	NREL
World Bank	Prototype	1999	13,800	4,490	Luz SEGS I in 1984	World Bank
World Bank	Prototype	1999	30,000	3,200-4,130	Luz SEGS II-VII built from 1984-	World Bank
World Bank	Estimate	1999	30,000	3,495	Estimate for 30MW	World Bank
APS Saguaro 1MW Plant	Commercial	2008	1,000	6,000	Saguaro plant with Organic Rankine	CH2MHill
CPV	**Type**		**Capacity (kW)**	**Capital Cost ($/kW)**	**Note**	**Source**
NREL	Range	2007		7000-8000	Tech roadmap gives 7,000-8,000	NREL
Navigant	Estimate	2006	15,000	5,000	Estimate	Navigant Consulting
SolFocus	Commercial	2009	92	*6,040*	Cost of 11 8.4kW for 92kW system	*News*
ORNL	Commercial	2007	150	6,500	Also has project breakdown	ORNL
Concentrix Solar	Commercial	2010	20,000	3,532	Paper on costs of FLATCON	Concentrix Solar

HEI

Hawaiian Electric Company, Inc.

CSP Benchmarking

Key Inputs		Tier 3	
Capacity Factor	%	18-21% trough 20-22% dish 22-24% CPV	SAM model results, 2006 NREL Report by B&V; Navigant's 2007 AZ Solar Electric Roadmap; combined with solar insolation comparisons btw. Mojave & HI, CPV from NREL 2009
Permitting Costs	$/kW	$30-$150	Hawaii specific estimates from Perry White, Planning Solutions
Interconnection Costs	$/kW	$250-$525	Low estimate $250/kW for a 5MW system and high estimate of $525/kw for a 1MW system on a $/kW basis
Equipment & Installation Cost	$/kW	$4700-$7050	Dish (recent CEC project estimate $6000/kW). Trough (recent estimates range from $3600-$6300/kW) CPV (recent estimates range from $3500-$6000/kW). 80% cost assumed equipment, 20% assumed installation. HI premiums included
Total Installed Cost	**$/kW**	**$5100-$7750**	
Insurance Cost	% CapEx per year	0.45%-0.55%	Assumed same as PV
O&M	$/KW-yr	$50 (CPV) $60-$70 (trough) $80-$100 (dish)	CPV - ORNL, Trough - B&V 2006, Dish - Navigant AZ roadmap
Land	$/acre	$5000-$15000	Land lease (3% annual increase), Dish (1 acre = 500kW), Trough (3 acre = 500 kW)

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

HEI

Permitting Costs – CSP

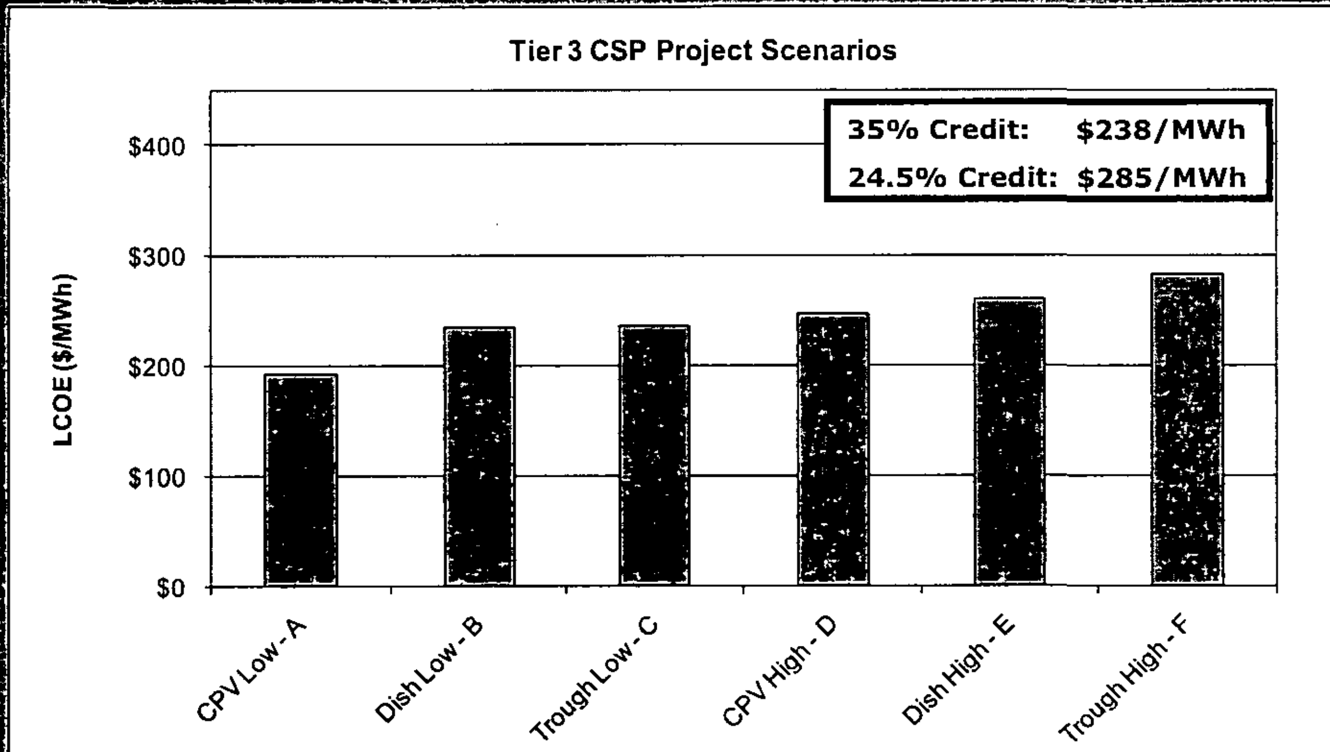
Low	Medium	High
$35,000	$90,000	$150,000
▪ < 1 acre of land disturbance ▪ Private property ▪ In the State Urban, Rural, or Agricultural District ▪ Does not require disturbance of high-value habitat ▪ Served by existing roads and transmission	▪ Envir. assess. needed ▪ Permits - Dept. of Health and/or the Comm. on Water Resource Management ▪ Modest amount of envir. field work ▪ Construction will not entail noise or traffic that require special studies	▪ > 1 acre disturbed (requires a NOI-C be filed with the State Dept. of Health) ▪ Preparation of a Chapter 343 Environmental Assessment ▪ Moderate amount of other work needed

Hawaiian Electric Company, Inc.

HEI

Hawaiian Electric Company, Inc.

Preliminary CSP Scenarios: State Tax Credit Monetized

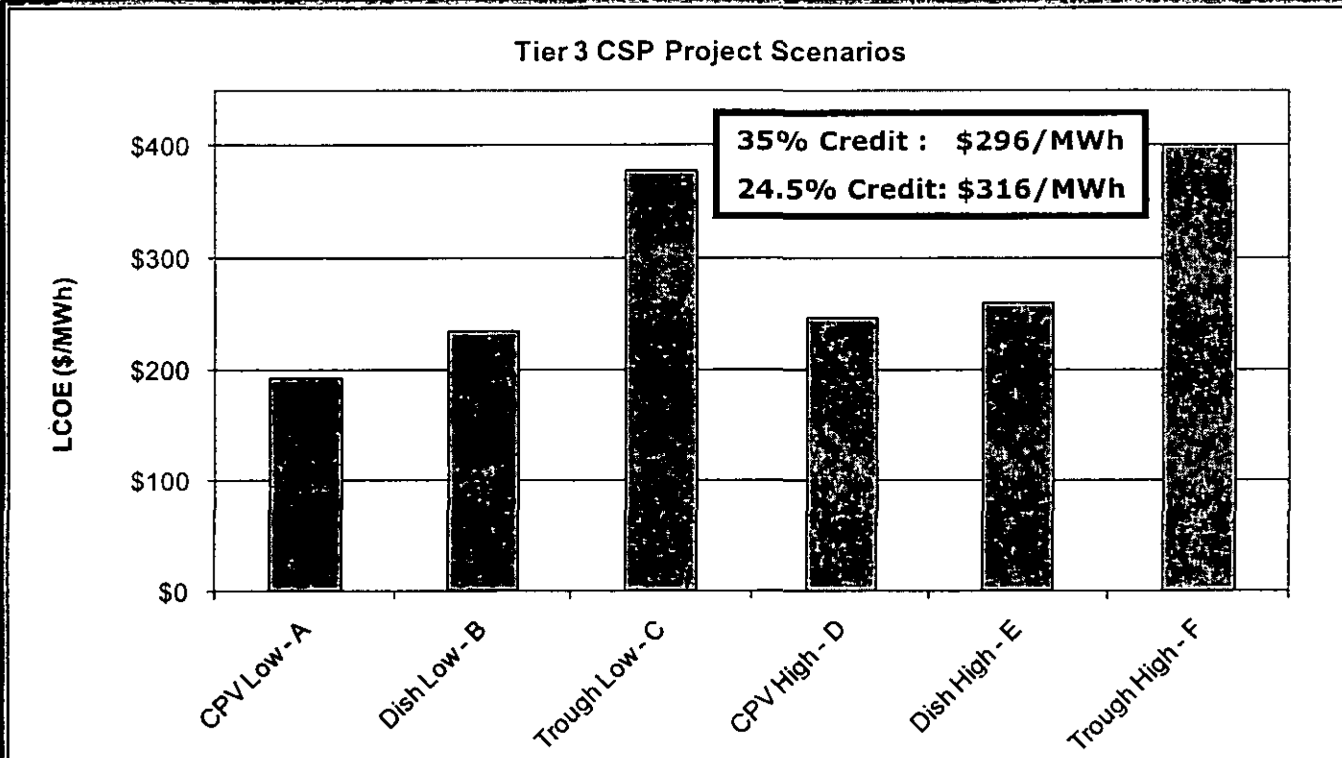


Key Inputs	A	B	C	D	E	F
Size (kW)	5,000	5,000	5,000	500	500	500
Capacity Factor (%)	23%	23%	21%	22%	21%	19%
Installed Cost ($/kW)	$6,169	$7,347	$6,758	$8,330	$8,919	$7,742
LCOE	$193	$235	$235	$246	$259	$283

HEI

Hawaiian Electric Company, Inc.

Preliminary CSP Scenarios: Limited State Tax Credit for Trough



Key Inputs	A	B	C	D	E	F
Size (kW)	5,000	5,000	5,000	500	500	500
Capacity Factor (%)	23%	23%	21%	22%	21%	19%
Installed Cost ($/kW)	$6,169	$7,347	$6,758	$8,330	$8,919	$7,742
LCOE	$193	$235	$377	$246	$259	$400

HEI

Hawaiian Electric Company, Inc.

CSP Pricing Issues for Discussion

- State Tax Credit Monetization
  - Trough systems tax treatment has large impact on overall CSP FIT rate if included
- Capacity factor assumptions
  - Sopogy has submitted lower capacity factor numbers that would increase the cost to $429/MWh

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FIT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

Wind Benchmarking Study

Key Inputs		Tier 3	Source
Capacity Factor	%	22-45%	NREL Mid-Scale Wind Wind Classes 3-7
Turbines & Towers	$/KW	$2000-$2600	LBNL ($1600-$2600)/manufacturer quotes ($2300)
Freight/Misc	$/KW	$150-$250	Freight 5% of turbine cost B&V 2004 IRP. Excise 4.72%
Site Development & Construction	$/KW	$1000-$1500	WES 250kW installation cost estimate with 50% HI labor/materials premium, site development & construction 25% of costs - (KEMA CEC COGS)
Permitting and Fees	$/KW	$100-$500	Hawaii specific estimates from Perry White, Planning Solutions, WES 250kW permit fee/processing estimate ($50-$100)
Interconnection	$/KW	$250-$525	Interconnection costs 5MW low end, 1 MW high end on a cost per kW basis
Total Installed Costs	**$/KW**	**$3500-$5000**	KEMA COGS - $2000-$4000; *NREL Mid-Scale Wind* - $2300-$3200
Insurance cost	% CapEx per year	0.45%-0.55%	Assumed same as PV
Land	% revenue	2-4%	AWEA
Fixed O&M	$/KW-yr	$15-$45	KEMA 2009 CEC COGS

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

HEI

DBEDT/HECO-IR-3
DOCKET NO. 2008-0273
ATTACHMENT 1
PAGE 32 OF 45

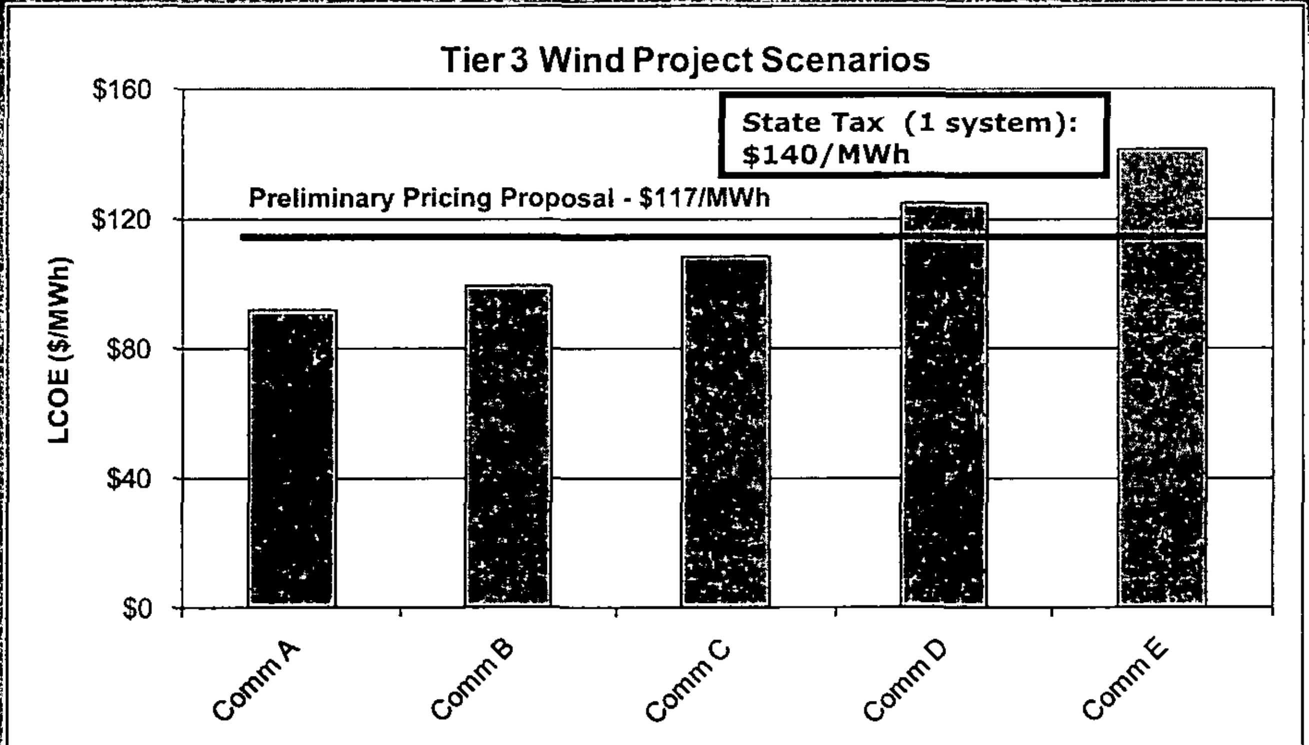
Hawaiian Electric Company, Inc.

Permitting Costs – Wind

Low	Medium	High
$15,000	$100,000	$500,000
▪ < 1 acre of land disturbance ▪ Private property ▪ In the State Urban, Rural, or Agricultural District ▪ Does not require disturbance of high-value habitat ▪ Served by existing roads and transmission	▪ Envir. assess. needed ▪ Permits - Dept. of Health and/or the Comm. on Water Resource Management ▪ Modest amount of envir. field work ▪ Construction will not entail noise or traffic that require special studies	▪ Habitat Conservation Plan ▪ Incidental Take Permit (US Fish and Wildlife Service) ▪ Incidental Take License (State of Hawai'i BLNS) ▪ > 1 acre disturbed (NOI-C) ▪ Chap. 343 Envir. Assessment

HEI

Preliminary Wind Scenarios



Key Inputs	A	B	C	D	E
Size (kW)	5,000	5,000	2,500	1,000	1,000
Capacity Factor (%)	36%	34%	32%	30%	28%
Installed Cost ($/kW)	$ 4,044	$ 4,054	$ 4,310	$ 4,858	$ 4,978
LCOE ($/MWh)	$92	$100	$108	$125	$141

Hawaiian Electric Company, Inc.

Tier 3 Preliminary Pricing Summary

	Tier 3 – Full Monetization	Tier 3 – 24.5%
PV	$190/MWh	$228/MWh
Wind	$117-$140/MWh (?)	NA
Hydro	$116/MWh (?)	NA
CSP	$238-$296/MWh (?)	$285-$316/MWh (?)

HEI

Hawaiian Electric Company, Inc.

Agenda

1. Review of FiT methodology
2. Discounted cash flow (DCF) model description
3. Universal benchmarks
4. PV benchmarks and scenarios
5. Hydro benchmarks and scenarios
6. CSP benchmarks and scenarios
7. Wind benchmarks and scenarios
8. Next Steps and Open Forum

HEI

Hawaiian Electric Company, Inc.

Next Steps

- Pricing set up to be a transparent and collaborative process
- Stakeholder benchmarking inputs including but not limited to:
  - Input on typical construction terms
  - Tax treatment process for CSP
  - Confirm tax treatment for wind
  - Resource availability for Tier 3 Hydro
  - Capex and capacity factor inputs for all technologies (ideally 3rd party verified)
- Tuesday, March 16 – Informal Exchange

HEI

Appendix

Hawaiian Electric Company, Inc.

HEI

Hawaiian Electric Company, Inc.

PV Preliminary Scenarios

	Scenarios					
Inputs	4 MW Fixed	3 MW Fixed	2 MW Fixed	4 MW Tracker	3 MW Tracker	2 MW Tracker
Size (kW dc)	4,000	3,000	2,000	4,000	3,000	2,000
Production (kWh/kW dc)	1,516	1,463	1,402	1,989	1,919	1,840
Annual degradation (%/year)	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
Curtailment (%/year)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Contract life	20	20	20	20	20	20
Capital Costs						
Modules ($/watt dc)	$ 1.60	$ 1.75	$ 1.90	$ 1.60	$ 1.75	$ 1.90
Inverters ($/watt dc)	$ 0.30	$ 0.35	$ 0.40	$ 0.30	$ 0.35	$ 0.40
Balance of System ($/watt dc)	$ 2.10	$ 2.30	$ 2.50	$ 2.50	$ 2.70	$ 2.90
Interconnection ($)	$ 1,250,000	$ 715,000	$ 715,000	$ 1,250,000	$ 715,000	$ 715,000
Permitting ($)	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Total	$ 4.33	$ 4.66	$ 5.20	$ 4.73	$ 5.06	$ 5.60
O&M Costs						
O&M ($/kW/year)	$ 17.00	$ 18.00	$ 19.00	$ 20.00	$ 21.00	$ 22.00
O&M escalator (%/year)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Other Costs						
Insurance (% CapEx/year)	0.45%	0.50%	0.55%	0.45%	0.50%	0.55%
Land ($/year)	$ 200,000	$ 150,000	$ 100,000	$ 360,000	$ 240,000	$ 140,000
Land (acres/MW)	5	5	5	9	8	7
Land escalator (%/year, 5 yrs)	3%	3%	3%	3%	3%	3%
Property Tax ($/year)	$ -	$ -	$ -	$ -	$ -	$ -
Type of System (Res./Comm.)	Comm.	Comm.	Comm.	Comm.	Comm.	Comm.
Financing						
Debt percentage (%)	35%	35%	35%	35%	35%	35%
Debt rate (%)	9%	9%	9%	9%	9%	9%
Debt tenor (years)	20	20	20	20	20	20
Construction debt perc. (%)	35%	35%	35%	35%	35%	35%
Construction debt rate (%)	11%	11%	11%	11%	11%	11%
Construction loan per. (mo.)	6	6	6	6	6	6
Equity rate (%)	11%	11%	11%	11%	11%	11%
Tax Incentives						
Federal ITC (%)	30%	30%	30%	30%	30%	30%
State ITC (%)	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Accelerated depreciation	5-Yr MACRS	5-Yr MACRS	5-Yr MACRS	5-Yr MACRS	5-Yr MACRS	5-Yr MACRS
CF	17.30%	16.70%	16.00%	22.70%	21.90%	21.00%
LCOE $/MWh (w/ HI tax cred)	$ 170	$ 188	$ 215	$ 164	$ 173	$ 188

HEI

Hawaiian Electric Company, Inc.

Hydro Preliminary Scenarios

Tier 3 Hydro Resources (CF 50%)					
100kW-5MW					
	Scenarios				
Inputs	Comm A	Comm B	Comm C	Comm D	Comm E
Size (kW)	5,000	2,500	1,000	500	500
Production (kWh/kW)	4,380	4,380	4,380	4,380	4,380
Curtailment (%/year)	0%	0%	0%	0%	0%
Contract life	20	20	20	20	20
System life	20	20	20	20	20
Capacity Factor	50%	50%	50%	50%	50%
Capital Costs					
Equipment	$900	$1,646	$2,469	$3,292	$5,250
Installation	$450	$750	$1,125	$1,500	$1,750
Permitting	$10	$12	$30	$60	$60
Interconnection	$250	$286	$525	$525	$525
Total Installed	$1,610	$2,694	$4,149	$5,500	$7,585
O&M Costs					
O&M ($/kW)	$50	$50	$50	$50	$50
Other Costs					
Insurance (% CapEx/year)	0.60%	0.60%	0.60%	0.60%	0.60%
Property Tax ($/year)	$0	$0	$0	$0	$0
Land (% revenue for lease)	4%	4%	4%	4%	4%
Financing					
Debt percentage (%)	35%	35%	35%	35%	35%
Debt rate (%)	9%	9%	9%	9%	9%
Debt tenor (years)	20	20	20	20	20
Construction Debt Percentage (%)	25%	25%	25%	25%	25%
Construction Loan Rate (%)	11%	11%	11%	11%	11%
Construction Period (months)	10	10	6	6	6
Equity rate (%)	11%	11%	11%	11%	11%
Tax Incentives					
Depreciation Years	20	20	20	20	20
PTC ($/MWh) for 10 years	$0	$0	$0	$0	$0
Federal ITC (%)	30%	30%	30%	30%	30%
State ITC (%)	0%	0%	0%	0%	0%
# of systems	1	1	1	1	1
Tax Rate (all in)	40%	40%	40%	40%	40%

HEI

Hawaiian Electric Company, Inc.

CSP Preliminary Scenarios

Tier 3 CSP

500kW-5MW

	Scenarios					
Inputs	CPV Low - A	Dish Low - B	Trough Low - C	CPV High - D	Dish High - E	Trough High - F
Size (kW)	5000	5000	5,000	500	500	500
Production (kWh/kW)	2015	2015	2015	1927	1840	1664
Curtailment (%/year)	0%	0%	0%	0%	0%	0%
Contract life	20	20	20	20	20	20
System life	20	20	20	20	20	20
Annual degradation (%/year)	0.75%	0%	0%	0.75%	0%	0%
Capacity Factor	23%	23%	21%	22%	21%	19%
Capital Costs						
Stirling Dish Capital Costs		$7,067			$8,244	
Solar Trough Capital Costs			$6,478			$7,067
CPV Capital Costs	$5,889			$7,655		
Interconnection	$250	$250	$250	$525	$525	$525
Hawaii Permitting	$30	$30	$30	$150	$150	$150
Total Installed Cost	$6,169	$7,347	$6,758	$8,330	$8,919	$7,742
O&M Costs						
Consolidated O&M ($/kWh)	50	80	$75	$50	$80	$75
Other Costs						
Insurance (% CapEx/year)	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Property Tax ($/year)	$0	$0	$0	$0		$0
Land ($/year)	$250,000	$100,000	$300,000	$25,000	$10,000	$30,000
Financing						
Debt percentage (%)	35%	35%	35%	35%	35%	35%
Debt rate (%)	9%	9%	9%	9%	9%	9%
Debt tenor (years)	20	20	20	20	20	20
Equity rate (%)	11%	11%	11%	11%	11%	11%
Construction Debt Percentage (%)	20%	20%	20%	20%	20%	20%
Construction Debt Rate (%)	11%	11%	11%	11%	11%	11%
Construction Debt Term (months)	12	12	12	6	6	6
Tax Incentives						
Depreciation Years	5	5	5	5	5	5
PTC ($/MWh) for 10 years	NA	NA	NA	NA	NA	NA
Federal ITC (%)	30%	30%	30%	30%	30%	30%
State ITC (%)	35%	35%	35%	35%	35%	35%
# of systems	35	35	35	5	5	5
Tax Rate (all in)	40%	40%	40%	40%	40%	40%

HEI

Hawaiian Electric Company, Inc.

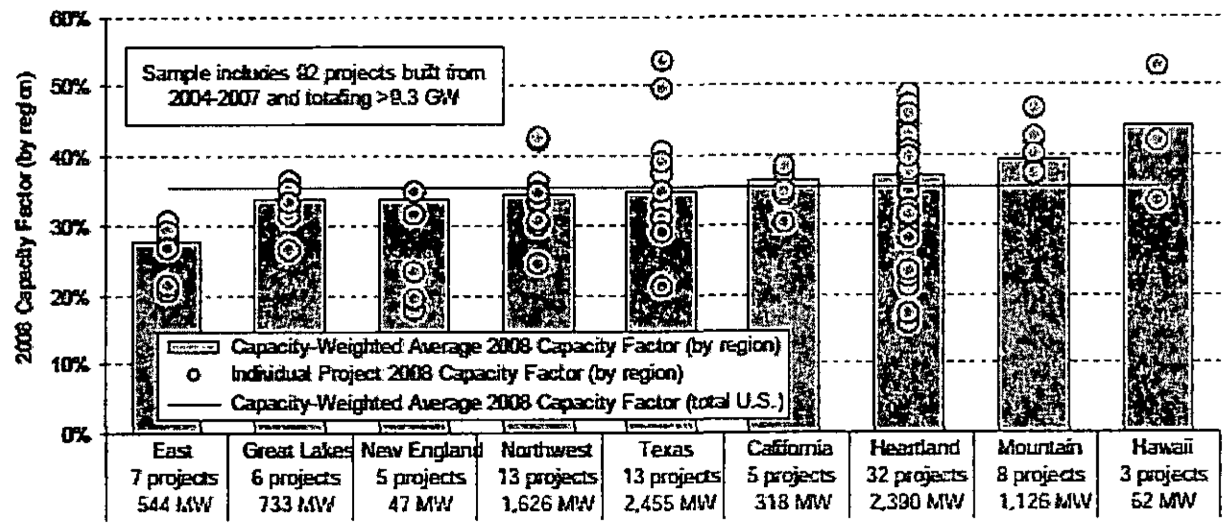
Wind Preliminary Scenarios

Tier 3 Wind Resources (+30% CF)					
100kW-5MW					
	Scenarios				
Inputs	*Comm A*	*Comm B*	*Comm C*	*Comm D*	*Comm E*
Size (kW)	5,000	5,000	2,500	1,000	1,000
Production (kWh/kW)	3,154	2,978	2,803	2,628	2,453
Curtailment (%/year)	0%	0%	0%	0%	0%
Contract life	20	20	20	20	20
System life	20	20	20	20	20
Capacity factor (after losses)	36%	34%	32%	30%	28%
Capital Costs					
Turbines ($/kW)	$ 2,000	$ 2,100	$ 2,300	$ 2,400	$ 2,600
Site Development & Construction ($/kW)	$ 1,500	$ 1,400	$ 1,300	$ 1,200	$ 1,100
Permitting and Fees ($/kW)	$ 100	$ 100	$ 200	$ 500	$ 500
Freight/Excise ($/kW)	$ 194	$ 204	$ 224	$ 233	$ 253
Interconnection/Electrical ($/kW)	$ 250	$ 250	$ 286	$ 525	$ 525
Total Installed ($/kW)	$ 4,044	$ 4,054	$ 4,310	$ 4,858	$ 4,978
O&M Costs					
O&M ($/kW/year)	$ 25.00	$ 30.00	$ 30.00	$ 30.00	$ 40.00
Land lease (% royalty on revenues)	4%	4%	4%	4%	4%
Other Costs					
Insurance (% CapEx/year)	0.6%	0.6%	0.6%	0.6%	0.6%
Property Tax ($/year)	$ -	$ -	$ -	$ -	$ -
Financing					
Debt percentage (%)	35%	35%	35%	35%	35%
Debt rate (%)	9%	9%	9%	9%	9%
Debt tenor (years)	20	20	20	20	20
Construction Debt Percentage	35%	35%	35%	35%	35%
Construction Loan Rate	11%	11%	11%	11%	11%
Construction Period (months)	10	10	6	4	4
Equity rate (%)	11%	11%	11%	11%	11%
Tax Incentives					
Depreciation Years	5	5	5	5	5
PTC ($/MWh) for 10 years	$ 21	$ 21	$ 21	$ 21	21
Federal ITC (%)	30%	30%	30%	30%	30%
State ITC (%)	20%	20%	20%	20%	20%
# of systems	7.00	7.00	4.00	2.00	2.00
Tax Rate (all in)	40.0%	40.0%	40.0%	40.0%	40%

HEI

Hawaiian Electric Company, Inc.

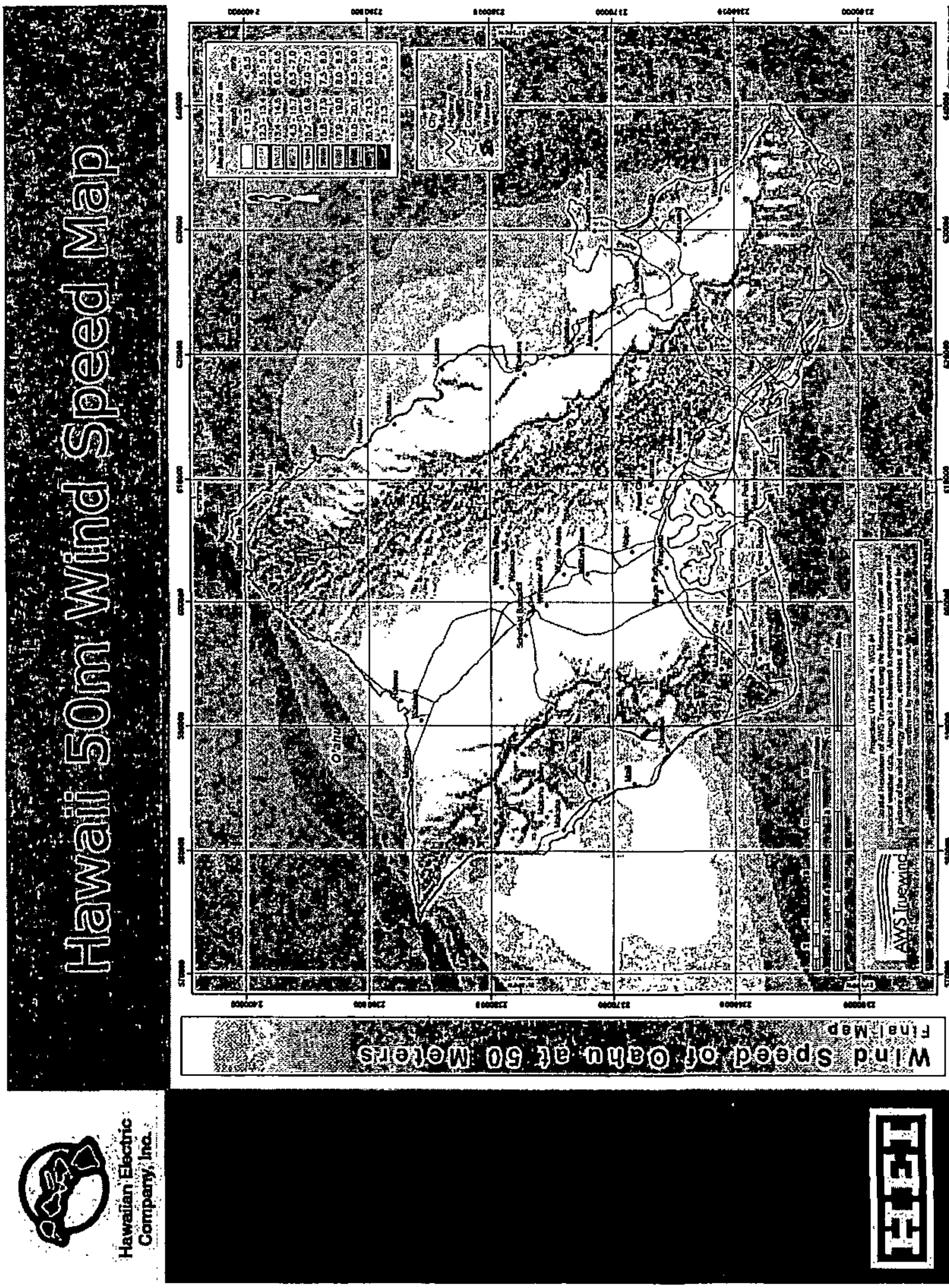
Hawaii Wind Resource



Source: Berkeley Lab database

Figure 25. 2008 Project Capacity Factors by Region: 2004-2007 Projects Only

HEI


Hawaii 50m Wind Speed Map
Wind Speed of Oahu at 50 Meters
Final Map
AWS Truewind
Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

Tier 2 Pricing for Comparison

	Tier 2 – 35%	Tier 2 – 24.5%
PV	$189/MWh	$238/MWh
Wind	$138/MWh	NA
Hydro	$189/MWh	NA
CSP	$254/MWh	$275/MWh

HEI

HECO Responses to DBEDT Questions

1. Why is the property tax zero in the spreadsheets? Is it included in the 40% tax rate? Or are all energy systems exempt from paying property taxes, hence the $0 property tax cost per year?

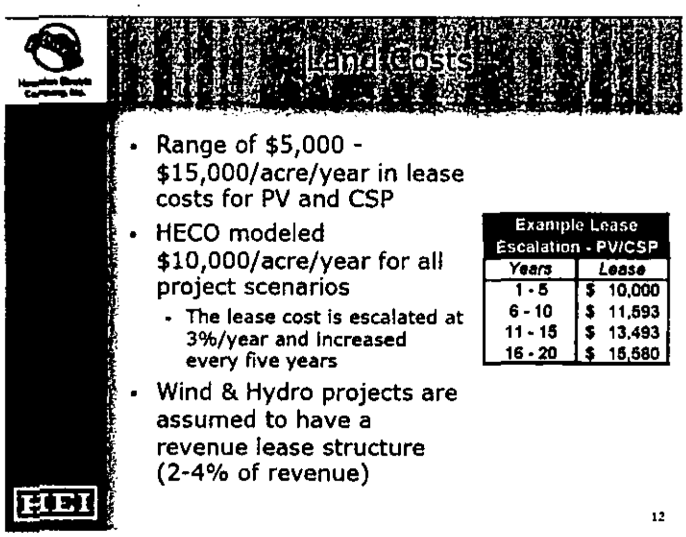
The property tax is zero in the spreadsheets because, effective September 29, 2009, alternate energy improvements on Oahu qualify for real property tax exemption for 25 years under Revised Ordinances of Honolulu Sec. 8-10.15 (applies to tax years beginning July 1, 2010 and thereafter). It is not included in the 40% combined federal/state income tax rate.

2. Land costs for CSP and PV systems increase every 5 years by a factor of 1.03^{5x}, where x is equal to one 5-year block. How is this appreciation derived? Why is this appreciation for land costs only factored in for CSP and PV but not for Wind or Hydro systems?

Please reference the land cost assumptions used for the calculation of FIT Tier 1 and Tier 2 rates in the HECO Companies' response to PUC-IR-330, filed with the PUC on March 4, 2010. Similarly, the land cost assumptions being utilized in the FIT Tier 3 cost of generation model differ by technology. For wind and hydro, a revenue lease structure was used whereby the lessor receives a certain portion of the project's revenue on an annual basis. This is the industry standard for the wind industry, and it was assumed to be the case for hydro because the land continues to have other purposes once the generating facility is placed in service, like in wind. A standard revenue lease rate of 2 - 4% of revenues on an annual basis is used, which is the wind industry standard. The high end of the range, or 4% of revenues on an annual basis, was selected as the input to the pricing model to reflect the relatively high cost of land in Hawaii.

For Tier 3 CSP and PV systems, it is assumed that a developer would be able to secure a lease for 20 years, and a land lease rate of $10,000/acre/year is used. A land cost escalator of 3% per year, compounded annually and applied to the rent every five years, is premised upon assessment of Oahu market data and trends. Please note that CSP/PV land costs are Wind/Hydro costs are calculated in a different fashion because they are fundamentally different types of projects in terms of how they occupy the land upon which they reside. In a wind or hydro lease, the land owner can still use the property because the turbines cover only a portion of the leased land. However, in a CSP or PV lease the land is completely covered by generating facility equipment, thereby rendering the land solely dedicated to the production of energy.

The land cost assumptions were discussed in depth on slide 12 of the March 10, 2010 workshop on Tier 3 pricing. A screen shot of that slide is pasted below for your convenience.



3. For each of the technologies (CSP, PV, Hydro, and Wind), can you please [provide] the worksheets and/or the data sources on how the fixed data for input assumptions were derived – i.e., all costs inputs including interconnection costs and what are included in the interconnection costs.

The specific worksheets that were used to calculate the LCOE for each technology were provided to the parties in an email from Rod Aoki at 5:24 pm on Wednesday, March 10, 2010. In addition, the methodology for developing rates and the specific benchmarking data was presented in PowerPoint form at the March 10, 2010 workshop; the interveners received hard copies of the presentation as well as an electronic copy of the presentation on the evening of March 9, 2010.

The broad range of inputs was derived through a benchmarking study for each technology. As discussed on slide 4 of the workshop presentation, each technology's LCOE analysis is sensitive to key project inputs that vary by technology. The pricing team's work provided a sensitivity analysis to inform decision making based on the key factor or factors that drive the LCOE. Below is a brief explanation of each technology's benchmarking study that was discussed in depth at the March 10, 2010 workshop, as well as the benchmarking slides from the presentation that contain specific references to the sources of the information. A few of the universal benchmarks (interconnection and permitting) are covered at the end.

<u>PV (slides 14 – 17):</u>
The pricing team attempted to obtain PV cost benchmarks from public sources, but there is not much information available publicly on the 500 kW - 5 MW size range of projects. There is a good database of installed project costs through the California Solar Initiative database, but those projects are 1 MW and below, and the numbers are not representative of current market conditions as the interveners saw from the process for Tiers 1 and 2. In addition, there are a few studies on cost of generation for larger projects, such as the RETI process that is underway in California, but those are for projects of 20 MW in size, well outside of the Tier 3 range.

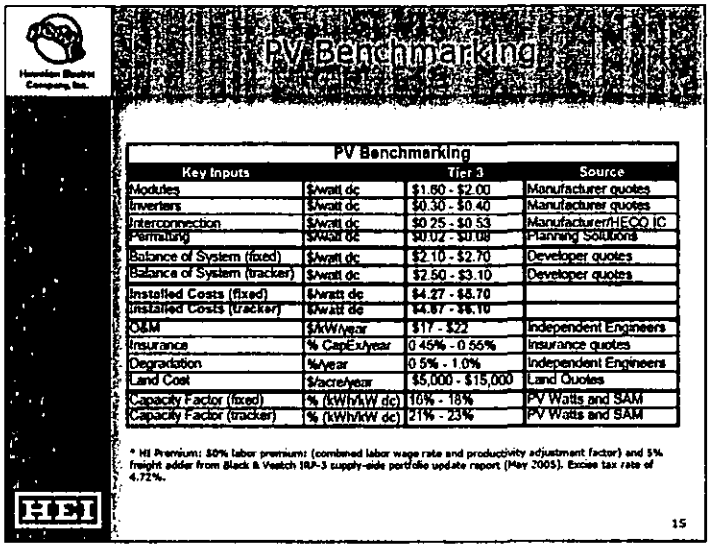
As such, we primarily worked off of PV quotes from manufacturers and developers to get a good range of installed costs. Many of the operating assumptions came from independent engineering estimates (O&M and degradation numbers). Insurance costs are from insurance quotes, because it was very difficult, if not impossible, to find publicly available information for HI-specific numbers. Land costs are from a variety of sources including HECO's in-house team, industry input, and real estate broker quotes in Hawaii (please see response to #1 above). We assumed 5 acres/MW dc for fixed tilt systems and 7 - 9 acres/MW for tracking systems.

Just as was done in Tiers 1 and 2, to the labor portion of the Balance of System of the Capital Cost, a 50% labor premium was added. That comes from HECO's IRP-3 from May 2005 and is due to a combination of labor wage and productivity adjustment factors. Inverter and panel prices were kept the same as mainland prices but excise tax was added to them.

We used the interconnection numbers discussed later in this response, as well as the permitting costs that were estimated by Planning Solutions, a local environmental permitting group.

The capacity factors assumptions that were used came from NREL data – specifically PV Watts and the SAM model. The capacity factors were estimated to be 16 – 17.3% for fixed tilt systems and 21 - 22.7% for tracking systems.

A screen shot of the PV benchmarking table from the workshop presentation is included below (slide 15).



PV Benchmarking

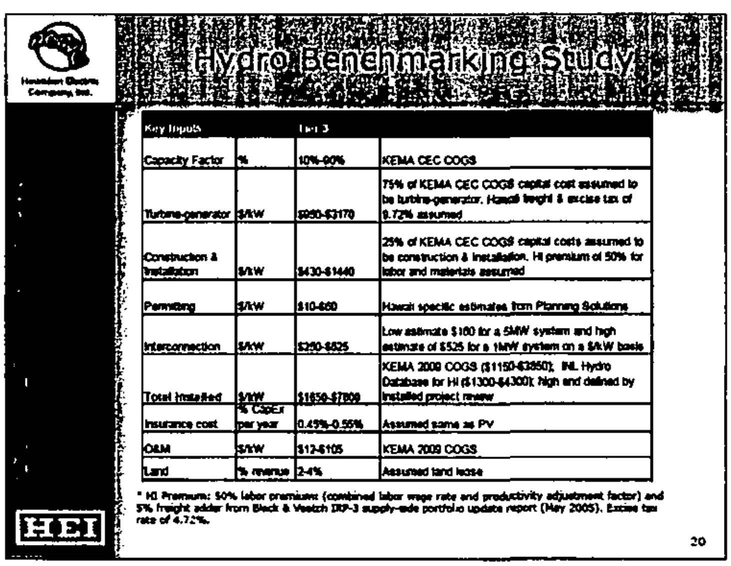
PV Benchmarking			
Key Inputs		**Tier 3**	**Source**
Modules	$/watt dc	$1.60 - $2.00	Manufacturer quotes
Inverters	$/watt dc	$0.30 - $0.40	Manufacturer quotes
Interconnection	$/watt dc	$0.25 - $0.53	Manufacturer/HECO IC
Permitting	$/watt dc	$0.02 - $0.08	Planning Solutions
Balance of System (fixed)	$/watt dc	$2.10 - $2.70	Developer quotes
Balance of System (tracker)	$/watt dc	$2.50 - $3.10	Developer quotes
Installed Costs (fixed)	$/watt dc	$4.27 - $5.70	
Installed Costs (tracker)	$/watt dc	$4.67 - $6.10	
O&M	$/kW/year	$17 - $22	Independent Engineers
Insurance	% CapEx/year	0.45% - 0.55%	Insurance quotes
Degradation	%/year	0.5% - 1.0%	Independent Engineers
Land Cost	$/acre/year	$5,000 - $15,000	Land Quotes
Capacity Factor (fixed)	% (kWh/kW dc)	16% - 18%	PV Watts and SAM
Capacity Factor (tracker)	% (kWh/kW dc)	21% - 23%	PV Watts and SAM

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

15

Hydro (slides 18 - 23):
The hydro benchmarking drew from the KEMA 2009 Cost of Generation report for the California Energy Commission which specifically analyzed the range of capacity factors and installed costs of in-conduit (or in-line) hydro generation. These costs were inflated to include Hawaii specific freight & excise tax and Hawaii specific labor and materials cost. In addition, we added the Hawaii specific permitting and interconnection costs discussed in further depth below. The permitting costs represent the high end of the range developed by Planning Solutions. The range in $/kW is due to the range in project sizes. The total installed cost ranges from $1650 - $7600. The high end of this installed cost takes the low end $/kW of installed cost for the smaller HI based systems. There are not any systems in this size range thus the low end was used because it is assumed with larger projects there should be economies of scale particularly for the turbine-generator. Insurance costs are assumed to be the same as PV. O&M costs were drawn from the KEMA Cost of Generation study and range from $12 - $105/kW. Land costs are assumed to be annual lease equal to 2 - 4% of annual revenue. Both wind and hydro projects allow for dual use of the land and thus have different land lease assumptions than PV and CSP.

A screen shot of the hydro benchmarking table from the workshop presentation is included below (slide 20).



Hydro Benchmarking Study

Key Inputs		Tier 3	
Capacity Factor	%	10%-90%	KEMA CEC COGS
Turbine-generator	$/kW	$950-$3170	75% of KEMA CEC COGS capital cost assumed to be turbine-generator. Hawaii freight & excise tax of 9.72% assumed
Construction & Installation	$/kW	$430-$1440	25% of KEMA CEC COGS capital costs assumed to be construction & installation. HI premium of 50% for labor and materials assumed
Permitting	$/kW	$10-$60	Hawaii specific estimates from Planning Solutions
Interconnection	$/kW	$250-$525	Low estimate $160 for a 5MW system and high estimate of $525 for a 1MW system on a $/kW basis
Total Installed	$/kW	$1650-$7600	KEMA 2009 COGS ($1150-$3850); INL Hydro Database for HI ($1300-$4300); high end defined by installed project review
Insurance cost	% CapEx per year	0.45%-0.55%	Assumed same as PV
O&M	$/kW	$12-$105	KEMA 2009 COGS
Land	% revenue	2-4%	Assumed land lease

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

20

<u>CSP (slides 24 - 30):</u>
The pricing team completed a lot more work on the CSP capacity factor assessment to focus on the Hawaii specific numbers. We also ran the trough systems through the SAM model using a Honolulu specific location and a 1 MW project size configuration, similar to the APS Saguro plant without storage. This gave the pricing team a range of 19 - 21% depending on the assumptions for the solar field ratio. This matched our direct calculation using the difference in insolation from Mojave to Honolulu. We used the same 70 - 75% insolation difference between Mojave and Honolulu to calculate the dish capacity factor range, the CPV range was from a 2009 NREL report that provided a comparison between CPV capacity factors in Mojave and in Los Angeles. In a comparison of Direct Normal Insolation (DNI), Honolulu, and Los Angeles are similar. If anything, Los Angeles has inferior insolation, thus using the Los Angeles based capacity factors is conservative.

Permitting costs range from $30 - $150/kW and come from a study by Planning Solutions. Interconnection costs are $250 - $525/kW and are discussed in further depth below.

We took the range of installed costs and added Hawaii premium for labor and freight. In order to do that we had to breakout the equipment costs from the installation costs. We assumed an 80%/20% breakout of equipment to installation costs. So 80% of the total installed costs were inflated by 109.72% representing the 5% freight and 4.72% excise tax and 20% of the costs were inflated by 150% to represent the Hawaii labor premium. Thus, the total installed costs range from $5,100 - $7,750/kW.

Insurance costs are assumed to be the same as PV at 0.45 - 0.55%. O&M costs were $50 for CPV, $60 - $70 for trough and $80 - $100 for CPV. Dish is assumed to require 1 acre for every 500 kW and trough requires 3 acres for every 500 kW.

A screen shot of the CSP benchmarking table from the workshop presentation is included below (slide 26).

CSP Benchmarking

Key Inputs		Tier 3	
Capacity Factor	%	18-21% trough 20-22% dish 22-24% CPV	SAM model results, 2006 NREL Report by B&V; Navigant's 2007 AZ Solar Electric Roadmap; combined with solar insolation comparisons btw. Mojave & HI, CPV from NREL 2009
Permitting Costs	$/kW	$30-$150	Hawaii specific estimates from Planning Solutions
Interconnection Costs	$/kW	$250-$525	Low estimate $250/kW for a 5MW system and high estimate of $525/kw for a 1MW system on a $/kW basis
Equipment & Installation Cost	$/kW	$4700-$7050	Dish (recent CEC project estimate $6000/kW). Trough (recent estimates range from $3600-$6000/kW) CPV (recent estimates range from $3500-$6000/kW). 80% cost assumed equipment, 20% assumed installation. HI premiums included
Total Installed Cost	$/kW	$5100-$7750	
Insurance Cost	% CapEx per year	0.45%-0.55%	Assumed same as PV
O&M	$/KW-yr	$50 (CPV) $60-$75 (trough) $80-$100 (dish)	CPV - NREL, Trough - B&V 2006, Dish - Navigant AZ roadmap
Land	$/acre	$5000-$16000	Land lease (3% annual increase). Dish (1 acre = 500kW). Trough (3 acre = 500 kW)

* HI Premium: 50% labor premium (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

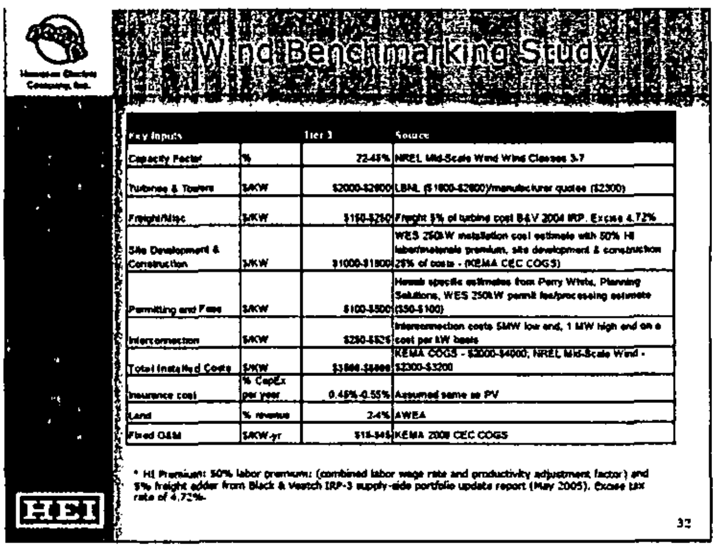
HEI

26

<u>Wind (slides 31 - 34):</u>
The capacity factor range for wind represents Class 3 - 7 from the NREL mid-scale wind study. The study provides energy production by wind class and turbine for several turbines within the Tier 3 size range. For our analysis we have focused on the turbines that range from 100 kW to 1 MW. This is due to the additional development and installation costs that come with larger turbine sizes of 1.5 MW+. This extra development/installation cost can make sense if you are building a larger 100 MW project size but for a smaller project of up to 5 MW, we did not think that it would make sense to move up to the larger turbines and, for example, pay for a large crane to be shipped from the mainland only to have that extra cost

allocated to one or two 1.5 or 2 MW turbines. Site development and installation costs were taken from the KEMA CEC COGS which focused on community scale wind projects within this range and added the HI premium. In addition, we looked at a specific installation cost estimate from a 250 kW WES turbine. Permitting costs range from $100 - $500/kW assuming that the projects use the high end of the permitting cost range discussed below. Interconnection, once again, ranges from $250 - $525/kW, and it is discussed in further depth below. Thus, the total installed costs are $3500 to $5000. To put these costs into perspective we would like to reference the final range of installed cost for community wind projects under the CEC COGS which was from $2000 - $4000 and the NREL Mid-Scale Wind study which had these size turbines installed costs ranging from $2300-$3200. Thus, the final installed cost range for Hawaii represents a substantial premium.

A screen shot of the wind benchmarking table from the workshop presentation is included below (slide 32).



Key Inputs		Tier 3	Source
Capacity Factor	%	22-45%	NREL Mid-Scale Wind Wind Classes 3-7
Turbines & Towers	$/KW	$2000-$2800	LBNL ($1800-$2800)/manufacturer quotes ($2300)
Freight/Misc	$/KW	$150-$250	Freight 5% of turbine cost B&V 2004 IRP. Excise 4.72%
Site Development & Construction	$/KW	$1000-$1800	WES 250kW installation cost estimate with 50% HI labor/materials premium, site development & construction 28% of costs - (KEMA CEC COGS)
Permitting and Fees	$/KW	$100-$500	Hawaii specific estimates from Perry White, Planning Solutions, WES 250kW permit fee/processing estimate ($50-$100)
Interconnection	$/KW	$250-$525	Interconnection costs 5MW low end, 1 MW high end on a cost per kW basis
Total Installed Costs	$/KW	$3500-$5000	KEMA COGS - $2000-$4000; NREL Mid-Scale Wind - $2300-$3200
Insurance cost	% CapEx per year	0.45%-0.55%	Assumed same as PV
Land	% revenue	2-4%	AWEA
Fixed O&M	$/KW-yr	$18-$45	KEMA 2008 CEC COGS

* HI Premium: 50% labor premium: (combined labor wage rate and productivity adjustment factor) and 5% freight adder from Black & Veatch IRP-3 supply-side portfolio update report (May 2005). Excise tax rate of 4.72%.

32

Interconnection:

Interconnection costs are assumed to be the same across the technologies. The cost for a 1 MW interconnection was $525,000. The cost for a 2.5 MW system was $715,000. The cost for a 5 MW system was $1,250,000. Please see the interconnection cost data from the workshop presentation (slide 11) below with specific line items for everything that is included in the interconnection cost.

Interconnection Costs					
1 MW		2.5 MW		5 MW	
Item	Cost	Item	Cost	Item	Cost
Interconnection Requirement Study	$ 25,000	Interconnection Requirement Study	$ 35,000	Interconnection Requirement Study	$ 75,000
SCADA and Direct Transfer Trip	$ 500,000	SCADA and Direct Transfer Trip	$ 500,000	SCADA and Direct Transfer Trip	$ 500,000
		12 kV line extension - 1,000 ft.	$ 100,000	46 kV line extension - 1,500 ft.	$ 150,000
		Transformer	$ 80,000	Transformers	$ 525,000
Total:	**$ 525,000**	**Total:**	**$ 715,000**	**Total:**	**$ 1,250,000**

These estimates came from HECO's internal interconnection team, as well as equipment manufacturer quotes for the transformers.

The Interconnection Requirement Study (IRS) cost information provided for the FIT pricing was developed using real available data (of which there were very few). HECO has not conducted a study for a 1 MW or 2.5 MW size project. It is working on a 5MW project (first ever for HECO) and the IRS cost for that is around $75,000. The $25,000 for the 1 MW given was based on a couple of HELCO projects which required IRSs. As for the 2.5 MW cost of $35,000, it was an estimate given that it is slightly larger than a 1 MW project, so $10,000 was added to the cost.

The line extension costs came from proprietary information that HECO in unable to release. The SCADA and Direct Transfer Trip are HECO estimates, and the transformer costs came from manufacturer quotes.

It is important to note that interconnection costs make up only a *very* small portion of the overall capital expenditures of a renewable energy project, and the resulting affect on the LCOE

<u>Permitting:</u>
The permitting cost methodology was covered in depth in a memo from Planning Solutions that was included in an e-mail distribution to the parties from Rod Aoki on Wednesday, March 10, 2010, 5:24 p.m..

DBEDT/HECO-IR-4
Ref.: Section L(1) – Application Fee
Please provide the workpapers showing the determination of the proposed non-refundable application fee of $2,500. Please include all assumptions and data sources used.

HECO Companies Response:

There are no workpapers for the proposed application fee of $2,500. The suggested fee was based on the fee used for HECO's Renewable Energy Request for Proposals.

DBEDT/HECO-IR-5

Ref.: Section L(2) – Reservation Fee
Please provide the workpapers showing the determination of the proposed fee of $15 /kW. Please include all assumptions and data sources used.

HECO Companies Response:

There are no workpapers for the proposed Reservation Fee of $15/kw. The amount proposed was based on discussions with HECO's consultant Merrimack Energy and the Independent Observer.

DBEDT/HECO-IR-6

Ref.: Section L(3) – Operating Period Security

a) Please explain the purpose and the basis of the "Operating Period Security" fee.
b) Please provide the workpapers showing the determination of the proposed "Operating Period Security" fee of $40/kW. Please include all assumptions and data sources used.
c) Are there any existing purchased power agreements with the same provision for "Operating Period Security"? If yes, please identify the purchased power agreement with the same provision. If no, please explain why not.

HECO Companies Response:

The question refers to the proposed Schedule FIT Tier 3, Section L.(3).

a) The purpose of the Operating Period Security fee is to guarantee the performance of the Seller's obligations under the Schedule FIT Tier 3 Power Purchase Agreement (PPA) for the period starting from the In-Service Date to the expiration or termination of the PPA.
b) There are no workpapers supporting the $40/kW fee. This amount is identical to the Operating Period Security fee in the Model PPA used in HECO's recently concluded 100 MW Request for Proposals for Renewable Energy. This amount was developed based on the experience in other jurisdictions of the Company's consultant, Mr. Wayne Oliver, as vetted by the Independent Observer. The amount attempts to balance the interests of the utility and its customers in having security, and the interests of all parties in having projects that can be financed.

c) Yes. The HECO – Kahuku Wind Power, LLC (KWP) Power Purchase Contract For As-Available Energy executed on July 2, 2009 and filed with the Commission on August 5, 2009 provides for KWP to post and maintain an Operating Period Security fee of $40/kW ($40,000/MW).

DBEDT/HECO-IR-7
Ref.: Section L(4) – Service Charge
Please provide the workpapers showing the determination of the proposed Service Charge of $25/month. Please include all assumptions and data sources used.

HECO Companies Response:

See Attachment 1 to this response.

PPA Metering Charge
Revenue Requirements Model
Summary of Revenue Requirement Factors

Year		General Meter 20-yr Term
1		0.14857
2		0.19990
3		0.19175
4		0.18381
5		0.17605
6		0.16846
7		0.16103
8		0.15375
9		0.14655
10		0.13936
11		0.13217
12		0.12498
13		0.11779
14		0.11060
15		0.10341
16		0.09622
17		0.08903
18		0.08184
19		0.07465
20		0.06325
Total		2.66318
Levelized at	8.58%	0.14971

Factors Applied to Est. Cost of $2,000/meter	
Levelized Per Year	299.42
Per Month = Levelized ÷ 12 rounded to nearest dollar	25.00

DBEDT/HECO-IR-8

Ref.: Power Purchase Agreement, Sec. 2.8, Page 18.

a) Please provide the basis for using the "average daily Base Rate at the Bank of Hawaii plus two percent (2%)" for the interest rate for late payment.
b) Please provide the workpapers showing the determination of the additional two percent (2%).
c) Please explain the rationale for the additional two percent.

HECO Response:

a) The charge for late payment in the Schedule FIT Tier 3 Power Purchase Agreement is identical to that in the Model PPA used in HECO's recently concluded 100 MW Request for Proposals for Renewable Energy and other recently negotiated PPAs.

b) There are no workpapers.

c) The rationale for the additional two percent is to incentivize HECO to pay the Seller's invoiced amount by the date specified in the PPA. In its administration of PPAs since 1991, HECO has never made a late payment which would have caused it to incur a late payment charge.

DBEDT/HECO-IR-9
Ref.: Power Purchase Agreement, Sec. 6.4, Page 22.
Is the cost of the equipment that is required of the Seller to install in order to forecasts as accurately as possible, included in the determination of the proposed FIT Energy Payment Rate provided in Section G of the SCHEDULE FIT TIER 3 tariff?

HECO Companies Response:

The HECO Companies Tier 3 Feed-In Tariff Power Purchase Agreement, March 2010 Version (3/16/10), states as follows:

"6.4 Equipment. In order to make Seller's forecasts as accurate as possible, Seller will install and maintain appropriate equipment for the purpose of forecasting (e.g., for wind projects, instrumentation to measure and record wind speed and direction; for PV projects, instrumentation to measure and record solar radiation)."

The cost of the measuring and recording equipment required for the purpose of forecasting is assumed to be sufficiently low as to be covered within the components of the installation costs input into the pricing models. Thus, the cost is included in the FIT Energy Payment Rate included in Section G of the Schedule FIT Tier 3 Tariff.

DBEDT/HECO-IR-10

Ref.: Power Purchase Agreement, Article 7, Page 22.

a) Is the "metering charge" of $25/month different from, and in addition to the Service Charge of $25/month "charged to the Seller for metering, billing, and administration of the Seller's purchased power…"? If the answer is yes, please explain why this would not result in double charging the Seller for the same cost (i.e. metering cost).

b) Please provide the workpapers showing the determination of the proposed Metering Charge of $25/month. Please include all assumptions and data sources used.

HECO Companies Response:

a) No. The Service Charge covers the metering.

b) This amount is consistent with what is currently being assessed to other purchase power contracts with HECO. See also HECO's response to DBEDT/HECO-IR-7.

DBEDT/HECO-IR-11

Ref.: Power Purchase Agreement, Section 8.2, Page 23.

a) Please explain what is meant by "negative avoided cost".
b) Please explain how HECO will determine this "negative avoided cost"? Please specify all the input data and data sources that HECO will use in determining this "negative avoided cost".
c) Has the Commission approved HECO's method for determining this "negative avoided cost"? If yes, please specify the docket number and the Commission's Order.

HECO Companies Response:

a. Avoided costs as defined in Hawaii Administrative Rules (HAR) 6-74-1 are the incremental or additional costs to an electric utility of electric energy or firm capacity or both which costs the utility would avoid by purchase from the qualifying facility. Avoided costs are calculated by comparing the utility's costs of generating power excluding the incremental power from a qualifying facility in the base case, with the utility's costs of generating that power including the incremental power provided by the qualifying facility in the alternate case. The difference between the cost of power in the base case and the alternate case is the avoided cost. When the cost of power in the base case is greater than the cost of power in the alternate case, the avoided cost is positive.

If, in order to accommodate the operation of a qualifying facility, the utility has to run its higher cost generating units when it otherwise did not have to, the utility would incur overall operating costs greater in the alternate case than it would in the base case. This would result in the avoided cost being negative. One example of this is if the utility is required to reduce output from lower cost base load units to accommodate purchases from qualifying facilities during light loading conditions. These base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to operate less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load units had the utility been able to operate at a constant output. If the cost of running the system with higher cost units during light loading periods (which includes the incremental power provided by the qualifying facility (the alternative case)) is greater than the cost of running the system with lower cost units (i.e. not allowing the qualifying facility to operate during the light loading period (the base case)), then there will be a negative avoided cost.

Title 18, CFR Section 292.304 (f) and HAR 6-74-24 both provide that if an electric utility gives at least twenty-four hours advance notice of a situation where purchases from a qualifying facility (the alternate case) will result in costs greater than those which the utility would incur if it did not make those purchases but generated an equivalent amount of energy itself (the base case), resulting in a negative avoided cost situation, it is not required to purchase power from the qualifying facility during these situations. Section 8.2 of the PPA addresses negative avoided cost situations.

b. If HECO does not purchase power from a qualifying facility because of a negative avoided cost situation, HECO will need to verify such a claim. HAR 6-74-24 (d) states that a claim by an electric utility that such a period of greater costs due to purchases from a qualifying facility has occurred or will occur is subject to verification by the Commission as the Commission determines necessary or appropriate, either before or after the occurrence.

c. HECO has not presented a method for determining negative avoided cost to the Commission for approval.

<u>DBEDT/HECO-IR-12</u>

Ref.: Power Purchase Agreement, Section 8.3, Page 24
Please explain how the provision on "No Curtailment for Economic Dispatch" provided in the referenced section is consistent with the provision on "Negative Avoided Cost" provided in Section 8.2.

<u>HECO Companies Response:</u>

Under Section 8.3, HECO is not allowed to curtail, interrupt, or reduce deliveries of electric energy from a Seller because the energy price negotiated in the PPA is higher than HECO's filed avoided energy cost data, or because that price is higher than that of other Sellers.

Pursuant to the operative sections discussed in response to DBEDT/HECO-IR-11, HECO is allowed not to purchase energy from the Seller during periods when HECO's <u>overall operating costs</u> with the Seller's generation included is higher than that without the Seller's generation, which is what is contemplated in Section 8.2 (Negative Avoided Cost).

DBEDT/HECO-IR-13

Ref.: Power Purchase Agreement, Section 10.1, Page 25.
Are the metering costs borne by the Seller as required in the referenced section included in the determination of the proposed FIT Energy Payment Rates in Section G of the SCHEDULE FIT TIER 3 tariff? If no, please explain why not.

HECO Companies Response:

As stated in the HECO Companies Tier 3 Feed-In Tariff Power Purchase Agreement, March 2010 Version (3/16/10), Section 10.1, "the Company shall purchase and own revenue meters suitable for measuring the Actual Output of the Facility sold to the Company...Company shall install, maintain and annually test such revenue meters and shall be reimbursed by Seller for all reasonably incurred costs for such installation, maintenance and testing work."

The costs to be borne by the Seller, i.e., "reasonably incurred costs for such installation, maintenance, and testing work[,]" are not currently included in the FIT Energy Payment Rate. The policy decision regarding Tier 3 meter cost-sharing remains to be determined.

Response to

Hawaii Renewable Energy Alliance's

Information Requests

HREA-IR-1.
First, HREA would like to reference the following reports: (i) General Electric Multi-Area Production Simulation (MAPS) models for the utility electric systems on the islands of Oahu, Hawaii and Maui, (ii) General Electric Positive Sequence load Flow (PSLF) models for the utility electric systems on the islands of Oahu, Hawaii and Maui, and (iii) Simulink model for the utility electric system on the island of Lanai. Is there anything (data, information and analysis) to suggest that it is NOT prudent to proceed with the initial pilot implementation? If so, please explain, because HREA does not believe HECO, to date, has produced such data, information and analysis.

HECO Response:

The Hawaiian Electric Companies utilize a number of modeling tools to plan for system needs at both the transmission and distribution levels. Presently, none of the HECO Companies have licenses to run GE Positive Sequence Load Flow (PSLF) (load flow) or GE Multi-Area Production Simulation (MAPS) (production costing) or Simulink tools for purposes of conducting system planning. GE tools require acquisition of proprietary software with licensing fees on the order of several hundreds of thousands of dollars. The HECO Companies currently use PTI/PSSE for load flow and dynamic analysis and primarily use PMONTH for production costing. PSS/E and PMONTH tools are currently maintained by the HECO Companies for purposes of system planning. These tools can be used in combination with other load flow and production simulation tools to conduct additional scenario analysis. The development of appropriate assumptions and model tuning would also have to be done in order to populate any of the other utility modeling tools to properly simulate the island systems. Because certain system data represents critical infrastructure data, this data must be protected under an appropriate non-disclosure agreement with distribution limited to those consultants required to and qualified to run these models.

With the increasing interests in solar and wind technologies, a number of utility planning software developers are creating new capabilities in their modeling software. GE, PTI, Siemens, PowerWorld, ABB and other utility modeling tool providers are working with utilities across the nation to continuously improve their tools and validate new modules. The Companies' efforts with Hawaii Natural Energy Institute (HNEI) support some of these model validation and tool enhancement initiatives through public-private collaborations that are also cost-shared with the U.S. Department of Energy ("DOE"). Current efforts that are using the GE planning tools are managed by the HNEI with funding from the DOE. HNEI has contracted GE Energy Consulting services to run GE's proprietary models and is working with the utilities to develop modeling capabilities and conduct "scenario-based" evaluation studies. As such, all reports issued by HNEI through these initiatives would be available to the public once finalized and issued by HNEI with approval from the U.S. DOE. In support of the Hawaii Clean Energy Initiative, the focus of a number of the HNEI 's transmission modeling research initiatives has been to improve the capabilities of industry modeling tools to properly resolve, integrate and model impacts of increasing penetration of intermittent renewables on the electrical grids. Of particular importance to the island grids, these planning models all need to be properly tuned to model the island generation units, operations and response times, incorporate appropriate wind and solar generator models and require some level of validation depending on the scope of the analysis. All of these utility modeling tools have to be "tuned" to some baseline that best represents the state of the system.

To date, HNEI has conducted 1) an initial study modeling the HELCO system, 2) is finalizing the report on a validation effort on the HECO and MECO systems, 3) is conducting

Scenario Analysis of the Inter-island Cable system integrating 400 MW of neighbor island wind to Oahu, and 4) is working on model improvements to capture a smart grid community demonstration on Maui. These studies have been used to project forward to a future state on the system and to investigate potential impacts on the systems and inform impacts and needs. For projects that have involved the utilities, assumptions on future load projections, unit responsiveness and minimum system limits have been supplied. These limits are then stressed using the model by conducting sensitivity analysis. Mitigation strategies to "fix" potential impacts are also then investigated utilizing the models. These technical options must then be further assessed in the context of the costs and benefits of implementation as mitigation strategies may increase costs to rate payers. The models provide options and inform the process for decision making but do not replace utility due diligence and detailed planning nor would they conclusively guarantee system reliability or offer protection in the event of system impacts. Utilities must still apply sound engineering, practical knowledge and prudent business strategies in the review of these options prior to seeking PUC approval.

As discussed above, an initial effort was funded by HNEI to model the Big Island system. Though some validation was performed for a year of known data (2006) to compare the theoretical results to the actual system performance, thorough benchmarking was not performed as the intent of the study was to provide a high-level perspective on the potential to accommodate renewable resources on the system. Accurate modeling of the dynamic response of HELCO's power system was not performed and the model was not tuned to accurately capture the operations of the HELCO system under various critical time frames. Both the MAPS and PSLF models used by the study for HELCO would need to be updated to reflect the refinement of data and new equipment on the HELCO system which currently are in the Company's planning models PMONTH and PTI/PSEE. Additionally, the GE tools are not appropriate for modeling distribution impacts thus none of the studies have incorporated any representation of the distributed generation (existing or future) on the HECO systems.

For MECO, GE Energy Consulting had developed a production cost model of the existing MECO system utilizing MAPS software and a transient dynamic system model of the existing MECO system on Maui using PSLF software. GE created reports (i.e. Deliverables) based on the scope of work defined in the GE proposal for the Maui Electric System Analysis Phase I. The reports focused on the following tasks of Data Consolidation and Preliminary Model Feasibility Analysis, Data Evaluation, Completion and Manipulation, System Model Development and Baseline Model Validation. Phase II of the Maui Electric System Analysis was not initiated and it would be speculative to suggest whether it is prudent or not prudent to proceed with an initial pilot for FIT implementation based on the Maui MAPS and PSLF modeling efforts to date.

The Simulink model referenced for the electrical system on the island of Lanai was produced by the Sandia National Laboratories. Currently, MECO does not have access to the model nor has MECO reviewed any analysis results from the Simulink model. Similar to the GE reports, it would be speculative to suggest whether it is prudent or not prudent to proceed with an initial pilot implementation based on the information from the Simulink model.

All modeling tools will require tuning and will not model all aspects of variable generation or the existing operations, an issue recognized industry-wide. Such issues may eventually lead to development of new planning tools or customization of existing planning tools to improve the modeling of variable generation resources for utility planning purposes. As such, they require close working collaboration with the utilities and the HNEI/HECO/GE efforts are an example of the Company's efforts to improve renewable modeling and evaluation of capabilities to best accommodate increasing levels to meet RPS targets.

Regarding prudency to proceed or NOT proceed with a suggested "pilot implementation", none of the GE efforts conducted through HNEI address FIT type level assumptions. Nor were these studies conducted by GE tailored or focused to address FIT integration issues on the system and therefore the results based on the referenced studies are not applicable to FIT. Analysis and assessments as well as data used filed with the Reliability Standards highlighted potential system conditions that would result in potential for reduction of system reliability. Those analysis provided as attachments recommended areas for further detailed assessment at both the distribution system level impacts (which require different tools than GE PSLF or GE MAPS) and the transmission system level impacts, which *may* potentially be able to leverage some of the prior GE work as referenced depending on what is being studied.

HREA-IR-2.

Given that HECO has not expressed concerns about the integration of FiT projects on Oahu in the pilot phase, HREA would like to focus on how potential "negative" impacts to the grids on Hawaii, Maui, Molokai and Lanai might be mitigated. For example:

1. would HECO propose to monitor the implementation of FiT, as well as Net Metering,
2. if so, how could that be accomplished,
3. in anticipation of potential "frequency regulation" problems in the pilot phase, is HECO willing to:
   a. allow greater frequency excursions, if they are limited in duration, e.g., a few seconds to few minutes, and/or
   b. if curtailment becomes necessary, due to the addition of new FiT projects, is HECO willing to compensate those systems that are curtailed, and thus preclude those projects, whether existing or new, from revenue loss.
4. in anticipating of full FiT implementation is HECO willing to consider:
   a. implementing additional ancillary services during the pilot phase for frequency regulation and possible peak shaving on Hawaii and Maui,
   b. working with all interested parties to prepare design and operating specifications for said ancillary services as a pilot project (s) on Hawaii and Maui, and
   c. expediting a competitive bidding process to implement the additional ancillary service technologies, such as batteries, on a pilot-project basis.

   Note: we believe this approach is warranted, not just as potential mitigation during the pilot FiT implementation, but also to test out ancillary service technologies for increased levels of renewable integration on our grids.

HECO Response:

1. The monitoring of FIT installations through SCADA is currently being proposed for certain Tier 2 and Tier 3 systems that have an aggregate capacity greater than 250kW for MECO and HELCOand greater than 500kW on HECO. The monitoring would provide high resolution kWh information and related solar resource information from these sites. SCADA offers the most direct means to interface with grid operations but as penetration levels increase, utilities may also find that additional monitoring may be needed at the distribution level. Consistent with a number of WECC utilities involved in the NERC IGVTF studies, HECO/MECO/HELCO will be deploying additional grid level

monitoring devices known as PMUs or synchrophasors to collect additional information on the system for purposes of improving controllability and visibility on the grid. Efforts leverage funding provided by U.S. DOE, federal ARRA stimulus and other grant funding sources. NEMs and Tier 1 and certain Tier 2 systems at present would be difficult to control even if cost-effective monitoring were available due to the sheer number of these smaller projects. Future technologies may also emerge as a part of Smart Grid or other industry developments for distribution monitoring and control but currently no cost-effective means exist. As penetration levels increase however, aggregated impacts must be assessed on a system-by-system, circuit-by-circuit basis and may require projects to provide solar isolation information. Characterizing the aggregated production from these distributed generators is currently being investigated for purposes of managing impacts on the distribution system through the High Penetration Solar Initiatives (partnership with California utilities and DOE labs). Thus, as proposed in the Companies' Reliability Standards filing, continued reassessment will likely be part of the larger system planning process as the "as-available" distributed resource penetration levels increase on each of the island systems. Costs for additional monitoring and control equipment and emerging demand side control technologies must also be appropriately considered to evaluate the impact upon ratepayers.

2. See response to part 1.
3. a. As described in the FIT Reliability filing, frequency control is a basic measure of system stability and reliability. Allowing greater frequency excursions by any grid-tied resource poses risks to utility generation equipment and customers' equipment which

would result in reduced reliability and stability, and therefore should be avoided regardless of duration.

b. The HECO Companies do not support compensation for curtailment as it would result in ratepayers paying for energy that is not delivered. Rather, projects should be encouraged to locate where overall system conditions indicate that excess energy curtailment can be mitigated or would be less likely.

4. The HECO Companies concur that mitigation technologies and practices are warranted during any pilot FIT implementation and have proposed a Working Group format to discuss and identify various suggestions and approaches. The Working Group format would provide visibility to all stakeholders on the results and cost impacts of additional mitigation measures.

Response to

The Solar Alliance
and
Hawaii Solar Energy Association's

Information Requests

SA/HSEA-T3-IR-1

Ref.: The HECO Companies have stated that "Land costs are from a variety of sources including HECO's in-house team, industry input, and real estate broker quotes in Hawaii." Did these sources base the land costs on Hawai'i PV projects? If not, why not. If yes, please identify the Hawai'i PV projects.

HECO Companies Response:

Land costs were derived from a number of sources. HECO has requested information from the interveners to see actual leases for renewable energy projects on Oahu, but the parties have not been able to provide them to date. As such, the only information that HECO has on specific solar projects in Hawaii is from the Department of Hawaiian Home Lands (DHHL), discussed below, because they are in the public domain. In addition, publicly-available costs for agricultural lands were used to establish the broader range of lease costs. The two DHHL lease proposals are outlined below and can be found at the following link on DHHL's website:

http://hawaii.gov/dhhl/beneficiary-consultation/renewable-energy-projects-kalaeloa-oahu

Sopogy lease proposal discussed at a public meeting on June 23, 2009 (http://hawaii.gov/dhhl/beneficiary-consultation/HHC%20D-5%20062309.pdf):

- $355,200 for 34 acres ($10,447.06/acre/year)
  - Increases by 25% over year 1 price in year 10 ($444,000)
  - Increases by 12.5% over year 10 price in year 16 ($499,500)
- Kalaeloa, Oahu

Recurrent Energy lease proposal discussed at a public meeting on October 20, 2009 (http://hawaii.gov/dhhl/beneficiary-consultation/HHC%20D-4%20102009.pdf):

- $302,760 for 29.853 acres ($10,141.69/acre/year)
  - Increases by 25% over year 1 price in year 10 ($378,450)
  - Increases by 12.5% over year 10 price in year 16 ($425,756)
- Kalaeloa, Oahu

The broader range of $5,000 - $15,000/acre/year as a starting point for the range of annual land lease costs (the leases in the modeling are assumed to have an escalation of 3%/year added to the lease cost every five years – 16% above year 1 cost in year 6, 34% above year 1 cost in year 11, and 56% above year 1 cost in year 16) was gleaned from the Hawaii market using publicly-available costs for agricultural lands in Hawaii. Because the two public solar leases fell in the middle of the range that was observed (~$10,000/acre/year – but at a lower escalator than HECO assumed), that is the price that was assumed for all solar projects. The following data points are a sampling of what was used to determine the broader land cost range:

- Kunia/Ewa large acreage: $2,000/acre/year
- Leeward side smaller acreage: $7,000 - $15,000/acre/year
- Kalaeloa Redevelopment (old Barbers Point NAS): $10,500/acre/year

SA/HSEA-T3-IR-2

In calculating the proposed rate for PV for Tier 3, why did the HECO Companies and their consultants use different capacity factors for different size PV projects? Please explain in detail and provide all supporting materials for using the different capacity factors.

HECO Companies Response:

As outlined in the March 10, 2010 Tier 3 Pricing Workshop ("Workshop") between the parties to the FIT proceeding, the capacity factor assumptions for Tier 3 changed because of the assumed system configuration for Tier 3 projects. Unlike Tier 1 and 2 projects which were assumed to be roof-mounted because of the size of the projects (0 – 500 kW), Tier 3 projects were mostly assumed to be ground-mounted with only the very low end of the capacity factor range being dictated by a flat, fixed-tilt project. As such, the range of capacity factors for different types of systems configurations change accordingly.

For Tier 1 and 2 projects, it was assumed that the range of capacity factors for roof-mounted systems was between 16% and 17%. These numbers were calculated using NREL's PV Watts 1 tool with Honolulu as the location, a 180 degree azimuth angle, a DC → AC derate ranging from 79 to 80%, and a tilt of 0 degrees to 10 degrees.

For Tier 3 projects, there were two types of system configurations modeled. All Tier 3 capacity factors were calculated using NREL's PV Watts 1 tool with Honolulu as the location and a 180 degree azimuth angle.

The first type of system configuration modeled within the Tier 3 project size range is a fixed tilt system, and those capacity factors ranged from 16% to 17.3%. The low end of the range was assumed to be a 0 degree tilt system with a DC → AC derate factor of 78.2%. The high end of the range is assumed to be a 20 degree tilt angle and an 80% DC → AC derate.

The second type of system configuration modeled within the Tier 3 project size is a tracking system, and those capacity factors ranged from 21% to 22.7%. The low end of the range was assume to be a 0 degree tilt single-axis tracker with a 76.3% DC → AC derate. The high end of the range was assumed to be a 20 degree tilted single-axis tracker with an 80% derate.

These capacity factors were also checked against NREL's Solar Advisor Model (SAM), and they were consistent.

To reiterate the message delivered to the interveners in the March 10, 2010 Workshop, these capacity factors are just one of the inputs that provide a *range* of resulting LCOEs, and the proposed FIT tariff is based on the mid-point of that range. So while there are certain capacity factors that correspond with certain size projects in the model, that is not the only capacity factor a project of that size could have. The intent of the modeling was to put upper and lower bounds on the range of reasonable Tier 3 projects.

SA/HSEA-T3-IR-3
In calculating the proposed rate for PV for Tier 3, please explain in detail and provide all supporting materials on how the HECO Companies and their consultants developed their debt equity ratios for PV. Is the proposed debt equity ratio based on any U.S. mainland PV Projects? If not, why not. If yes, please identify the U.S. mainland PV projects.
Is the proposed debt equity ratio based Hawaii PV projects? If not, why not. If yes, please identify the Hawai'i PV projects.

HECO Companies Response:

As discussed during the March 10, 2010 Workshop presentation, the debt/equity ratio used in the modeling for all Tiers of projects (35% debt/65% equity) has been seen primarily on the mainland. Even with the projects on the mainland, however, there is very little, if any, public data on the capital structure as the information is generally proprietary. The capital structure data has been gleaned by talking to developers and investors, as well as sample modeling of renewable energy projects using a more sophisticated model. HECO has requested evidence of debt/equity ratios (i.e. debt documents, equity documents) for Hawaii-specific projects from the parties, but no such data has been provided to HECO.

In the Renewable Energy Transmission Initiative (RETI) process on the West coast, a debt/equity ratio of 60%/40% to model renewable energy projects. Granted, these projects are larger in size (~20 MW) and can therefore attract capital more easily, but that can still be used as a data point. The assumed debt percentage of 35% is much lower and more reasonable for a smaller (~5 MW project) and should also be viewed as conservative. In the Long Term Procurement Plan (LTPP) currently underway in California a similar levered structure is being used in the modeling efforts, although in that the there is a higher percentage of debt on those projects, as well, so 35% can be viewed as conservative.

It is also important to note that SA/HSEA supported the Tier 1 and 2 rates developed using the same methodology, including debt/equity ratio.

SA/HSEA-T3-IR-4

Ref: The HECO Companies and their consultants confirmed during the March 10, 2010 Tier 3 Workshop that their permitting costs for PV for Tier 3 do not include legal fees and costs.

a. What would the permitting costs for PV for Tier 3 be if legal fees and costs were included?

b. Would this change the HECO Companies' proposed rate for PV for Tier 3? If yes, by how much?

HECO Companies Response:

The permitting costs specifically outlined in the Planning Solutions memo distributed to the parties in an email from Rod Aoki to the interveners on March 10, 2010, 5:24 pm did not include the legal costs associated with securing permits. However, the transaction costs for project development (including legal fees) are included in the Balance of System benchmarking costs for all technologies.

SA/HSEA-T3-IR-5

Ref.: The HECO Companies and their consultants have stated that the estimated interconnection costs "are assumed to be the same across the technologies" and "came from HECO's internal interconnection team, as well as equipment manufacturer quotes for transformers."

Did HECO's internal interconnection team and the equipment manufacturer quotes derive their costs based on Hawai'i PV projects? If not, why not. If yes, please identify the projects.

HECO Companies Response:

The interconnection requirement study (IRS) cost is based on actual studies completed for Hawaii PV projects. The SCADA cost is estimated based on the installation cost of equipment required since HECO has not implemented SCADA for projects of Tier 3 size. However, the estimate is a Hawaii-specific estimate. The line extension cost is an average of all the projects HECO performed in 2009 and covers a general line extension to serve customers.

SA/HSEA-T3-IR-6

Ref.: The HECO Companies and their consultants have stated that "the $25,000 [interconnection cost] for the 1MW given was based on a couple of HELCO projects which required IRSs."

Please identify these projects.

HECO Companies Response:

The two HELCO projects with completed IRS were Kona Commons and Koyo USA.

SA/HSEA-T3-IR-7

Ref.: During the March 10, 2010 Tier 3 Workshop, the HECO Companies agreed to provide the cost of all IRSs that they have done to date.
Please provide that information or provide a date by which the parties will receive the information.

HECO Companies Response:

For the Tier 3 size projects, the HECO companies have only completed two IRSs to date which were the Kona Commons (~$30,000) and the Koyo USA (~$27,000), both HELCO projects. These are the only two completed IRSs for Tier 3 size projects. More information will be provided on the estimated costs of IRS studies that are currently planned or in-process for projects that would be in the Tier 3 size range in the April 29, 2010 filing.

SA/HSEA-T3-IR-8

a. Please explain in detail and provide all supporting materials as to how the HECO Companies and their consultants derived the estimated costs for modules, inverters, and balance of systems for PV projects in Hawai'i.

b. Are these estimated costs based on Hawai'i PV projects? If not, why not. If yes, please identify the projects?

HECO Companies Response:

As discussed in the March 10, 2010 Tier 3 Pricing Workshop ("Workshop") between the parties to the FIT proceeding, the pricing team attempted to obtain PV benchmarking inputs, including capital costs, from public sources. However, there is very little information in the public domain on this topic specifically – the 500 kW - 5 MW project size range. There is a good database of installed project costs in California through the California Solar Initiative database, but those projects are 1 MW and below so only cover a fraction of Tier 3 sizes and the numbers are out-dated due to the significant drop in PV module and system costs in 2009 and the first part of 2010. In addition, there are a few studies on cost of generation for larger projects, such as the RETI process that is underway in California, but those are for projects of 20 MW in size and greater.

As such, the pricing team primarily worked off of PV quotes from manufacturers and developers to get a good range of installed costs. These quotes were primarily based off of mainland projects, but the costs were adjusted for a Hawaii premium. To the labor portion of the Balance of System of the Capital Cost, we added a 50% labor premium to account for higher labor costs in Hawaii. That comes from HECO's IRP-3 from May 2005 (Docket No. 03-0253) filed October 28, 2005, and is due to a combination of labor wage and productivity adjustment factors. We kept inverter and panel prices the same as mainland prices but added the excise tax to them.

HECO has requested specific capital cost numbers for recent Hawaii-based PV projects in the Tier 3 size range, but the parties have not been able to furnish any specific capital cost numbers to date.

SA/HSEA-T3-IR-9

Ref.: Proposed Tier 3 Tariff, section L.3.

a. Please explain the need for an "Operating Period Security" in the Tariff.

b. Please identify any language in the Commission's September 25, 2009 Decision and Order which supports the requirement of an "Operating Period Security" in the Tariff.

HECO Companies Response:

a. The Operating Period Security fee is necessary to guarantee the performance of the Seller's obligations under the Schedule FIT Tier 3 Power Purchase Agreement (PPA), for the period starting from the In-Service Date to the expiration or termination of the PPA. Please also see response to DBEDT-IR-6 subpart b.

b. In the Non-Rate Terms and Conditions section of the Decision and Order, the Commission stated: "Zero Emissions and Blue Planet argue that FIT projects should have no obligation to sell renewable energy to the utility for the duration of the FIT term since "the loss of revenue from a failure by the FiT participant to deliver renewable energy to the utility is penalty enough." [FN153] *The commission, however, disagrees.*" (Emphasis added). P. 85.

The Commission also stated: "Projects above 20 kW (i.e. Tiers 2 and 3) must also provide at least three months advance notice to the utility and the commission prior to ceasing operation for reasons other than *force majeure* events or be subject to penalties. This provision prevents sudden departures of anticipated generation and the resulting cost and reliability consequences. This requirement does not apply to projects of 20 kW or less (i.e., Tier 1), given their limited individual potential system effects and the undue burden it would place on residential or small business project owners." P. 86-87.

HECO interprets these statements as the Commission's requirement that FIT Tier 3 participants must adhere to the terms of the PPA over the contract period. The Operating Period Security fee is the mechanism by which HECO can ensure that Sellers will meet their obligations under the PPA.

Response to

Sopogy Inc's

Information Requests

HECO Companies-IR-1

Reference: Tier 3 LCOE, Capacity Factor Input

In the Levelized Cost of Energy Model developed by Black and Veatch utilized to develop the HECO Companies' Proposed Tier 3 rates (the "Tier 3 LCOE Model"), circulated to the parties on February 9, 2010, the HECO Companies input a capacity factor for concentrating solar power ("CSP") technologies on the Island of Oahu of 24%. Further, in the presentation (the "Workshop Presentation") distributed for discussion during the Tier 3 workshop, held March 10, 2010, the HECO Companies set forth a capacity factor range from 18-21% for CSP trough technology, 20-22% for Stirling Dish technologies and 22-24% for concentrating photovoltaic (CPV) technologies. Please provide specific technology data to support these ranges from commercial installations on the Island of Oahu, or in the alternative, specific data from the non-Hawaii installations relied upon and a step-by-step analysis and calculation of how data from commercial installations was adjusted for the specific Direct Normal Irradiance (DNI) levels and other relevant factors, if any, on the Island of Oahu.

HECO Companies Response:

The circulation of the LCOE Model on February 9, 2010 included illustrative inputs only. This was clarified in the email and on the models themselves. The model was distributed so that the stakeholders would be able to review the changes to the construction financing and provide feedback on inputs before the March workshop. The inputs in the model were placeholders and it was assumed that the stakeholders would review and provide feedback to the pricing team on the model itself and provide their inputs and documentation to aid the pricing team in benchmarking efforts.

The HECO companies hosted a workshop on March 10, 2010, where the pricing team presented their best knowledge and current assumptions for inputs to the model including capacity factor assumptions for the stakeholders to provide feedback. After the workshop, the HECO companies pricing team representatives had a call with Sopogy to specifically get their feedback on capacity factor assumptions. Subsequent to the call, Sopogy provided capacity factors for their planned Kalaeloa facility with a range of solar field ratios from 1:1 (18% capacity factor), 1.2:1 (21% capacity factor) and 1.5:1 (24% capacity factor). Sopogy also provided estimates for capital costs given the solar field ratio and the additional land required to oversize the field. Sopogy's capacity factor range is now similar to the pricing team's calculation for trough in Hawaii and the pricing team feels the results are stronger due to this collaborative process and appreciates Sopogy's willingness to participate to get a better answer. The pricing team will review the land and capital cost assumptions in the trough scenarios before finalizing the FIT scenario analysis for CSP.

The pricing team derived the capacity factor for CSP technologies in Hawaii using public sources since no commercial facilities are installed on Oahu. The pricing team used capacity factors for trough systems from the 2009 RETI assumptions which reviewed projects in the WECC (Western Electricity Coordinating Council). The capacity factor range for projects within this region ranged from 20%-28% for dry cooled projects (previously the range was 22-32% for wet cooled projects). The 2009 update to the RETI assumptions can be found here: http://www.energy.ca.gov/reti/steering/workgroups/phase2A_update/2009-11-19_meeting/RETI_Phase_2B_WG_Presentation_2009-11-19.pdf.

However, the DNI in Hawaii is not as strong. A HI specific solar study from 1992 showed that for trough the reduction in DNI on the aperture plane was roughly 25% for HI as compared to the best solar resources in the Mojave. See table III-6 in the study (Solar (Thermal) Electric Generating System (SEGS) Assessment for Hawaii) which can be found on the DBEDT publications website (http://hawaii.gov/dbedt/info/energy/publications/). There is also a cloud effect which was not specifically quantified. The study estimated that could cause an addition 10-15% reduction, however, it is not clear since the study is from 1992 if current technology would be able to ride out inter-hour cloud issues better.

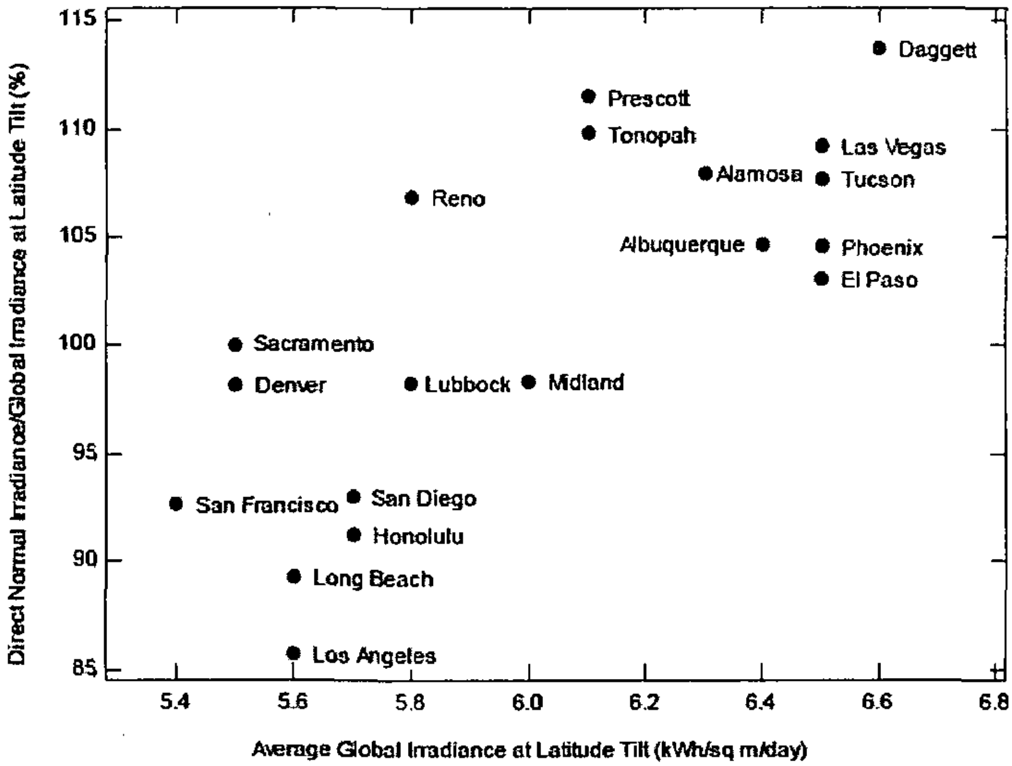
Therefore, to get to a HI specific range using the public sources vetted through the RETI stakeholder process, the top end of the range was assumed to represent Mojave and adjusted by multiplying by 75% to account for the 25-40% reduction in DNI. If assumed dry cooled 28% multiplied by 75% equals 21% and if wet cooled 32% multiplied by 75% is 24%. This represents the high end of the range as some cloud effect is likely. The low end assumes an additional 10% reduction due to clouds. If dry cooled, 28% multiplied by 65% is 18% and if wet cooled 32% multiplied by 65% is 21%. The full range is thus 18-24%. The pricing team modeled 19% and 21% conservatively in the scenarios. Given the new information from Sopogy, the pricing team will review the capital cost assumptions to make sure they allow for oversizing of the solar fields.

In addition, the pricing team used NREL's Solar Advisor Model ("SAM") to validate the capacity factor assumptions for trough. Although SAM's CSP Reference Manual is currently only available in its draft version, this was used as a reference point to decide what default inputs to change in order to reflect a typical 2.5MW installation in Hawaii.

In the SAM model, the Parabolic Trough System was selected and the location was set to Honolulu, HI. In the model's solar field options, the solar multiple was changed to 1.5 and the solar collector angle was set to -20 degrees (this negative angle tilts down the southern end of a solar array in the northern hemisphere). In the power block options, the Rated Turbine Net Capacity was set to 2.5MWe and the Design Turbine Gross Output was set to 2.75MWe, 110% of the rated capacity. The "SAM/CSP Trough Power Cycles/APS Ormat 1MWe 300C" power block was selected along with the respective "APS 1MW ORC Wet" parasitic system. Lastly, the Thermal Energy Storage Hours was set to 0 in order to model a system without storage. Using these modified inputs for the SAM model simulation gives an annual net electric output 4,492MWh which is equivalent to a 20.5% capacity factor. This capacity factor fell within the range of the calculation method from the public RETI process and gave the pricing team more confidence in the estimated range.

Dish capacity factors were estimated by Navigant to be between 22-30% in their AZ roadmap. Although they suggested typical capacity factors were at the low end of this range, more recently, dish manufacturers have emphasized that their technology superior capacity factor's at the top end of the range of conversion at 30-32%. Dish technology efficiency is related to DNI, and thus the Hawaii specific numbers should be lower than the high level of efficiency with a reduction between 25-35% from the Mojave level insolation using the same methodology as used with trough. Thus, the capacity factor range for Hawaii was estimated to be between 20-23%. The scenarios modeled used 21% and 23%, respectively.

A CPV specific study, "Opportunities and Challenges for Development of a Mature Concentrating Photovoltaic Power Industry", published by NREL in 2009 shows capacity factors at 23% in Los Angeles which has a similar insolation profile as Honolulu, Hawaii. The report can be found at the following link. (http://www.nrel.gov/pv/pdfs/43208.pdf) The DNI comparison chart is provided below for your convenience.


Daggett
Prescott
Tonopah
Las Vegas
Alamosa
Tucson
Reno
Albuquerque
Phoenix
El Paso
Sacramento
Denver
Lubbock
Midland
San Francisco
San Diego
Honolulu
Long Beach
Los Angeles
115
110
105
100
95
90
85
5.4
5.6
5.8
6.0
6.2
6.4
6.6
6.8
Direct Normal Irradiance/Global Irradiance at Latitude Tilt (%)
Average Global Irradiance at Latitude Tilt (kWh/sq m/day)

HECO Companies-IR-2
Reference: The Workshop Presentation
To the extent not provided in response to HECO Companies IR-I above, please provide specific annual capacity performance data and efficiencies, if any, from and the location of the commercial projects utilizing Stirling Dish and CPV technologies that were used in the Tier 3 LCOE Model or the Workshop Presentation.

HECO Companies Response:

The data used to calculate capacity factors is provided in the response to HECO Companies-IR-1. The pricing team has consistently asked the stakeholders to provide additional benchmarking data. Sopogy participated in follow-on discussions after the March workshop where they provided calculations for an Oahu based project with various solar field ratios and resulting capacity factors between 18-24%. This was consistent with the range proposed.

HECO Companies-IR-3
Reference: Tier 3 LCOE Model, Oahu Land Cost Input
Please explain the Oahu land costs and increases reflected in the Tier 3 LCOE Model and provide specific support, including actual quotes for Oahu agricultural, commercial and/or industrial parcels, leases or similar information, supporting those costs and increases. Also, please provide specific support for the $5,000-15,000 estimated land cost set forth in the Workshop Presentation.

HECO Companies Response:

Land costs were derived from a number of sources. HECO has requested information from the interveners to see actual leases for renewable energy projects on Oahu, but the parties have not been able to provide this information to date. As such, the only information that HECO has on specific solar projects in Hawaii is from the Department of Hawaiian Home Lands (DHHL), discussed below, because they are in the public domain. In addition, publicly-available costs for agricultural lands were used to establish the broader range of lease costs. The two DHHL lease proposals are outlined below and can be found at the following link on DHHL's website:

http://hawaii.gov/dhhl/beneficiary-consultation/renewable-energy-projects-kalaeloa-oahu

Sopogy lease proposal discussed at a public meeting on June 23, 2009 (http://hawaii.gov/dhhl/beneficiary-consultation/HHC%20D-5%20062309.pdf):

- $355,200 for 34 acres ($10,447.06/acre/year)
  - Increases by 25% over year 1 price in year 10 ($444,000)
  - Increases by 12.5% over year 10 price in year 16 ($499,500)
- Kalaeloa, Oahu

Recurrent Energy lease proposal discussed at a public meeting on October 20, 2009 (http://hawaii.gov/dhhl/beneficiary-consultation/HHC%20D-4%20102009.pdf):

- $302,760 for 29.853 acres ($10,141.69/acre/year)
  - Increases by 25% over year 1 price in year 10 ($378,450)
  - Increases by 12.5% over year 10 price in year 16 ($425,756)
- Kalaeloa, Oahu

The broader range of $5,000 - $15,000/acre/year as a starting point for the range of annual land lease costs (the leases in the modeling are assumed to have an escalation of 3%/year added to the lease cost every five years – 16% above year 1 cost in year 6, 34% above year 1 cost in year 11, and 56% above year 1 cost in year 16) was gleaned from the Hawaii market using publicly-available costs for agricultural lands in Hawaii. Because the two public solar leases fell in the middle of the range that was observed (~$10,000/acre/year – but at a lower escalator than HECO assumed), that is the price that was assumed for all solar projects. The following data points are a sampling of what was used to determine the broader land cost range:

- Kunia/Ewa large acreage: $2,000/acre/year
- Leeward side smaller acreage: $7,000 - $15,000/acre/year
- Kalaeloa Redevelopment (old Barbers Point NAS): $10,500/acre/year

HECO Companies-IR-4
Reference: The Workshop Presentation
Please provide specific support for the land requirements of 3 acre per 500kW for CSP trough projects and I acre per 500kW for commercial Stirling Dish projects. What are the estimated land requirements for commercial CPV and Stirling Dish facilities?

HECO Companies Response:

The land requirements were taken from the 2006 NREL CSP Analysis by Black & Veatch which can be found at the following link: http://www.nrel.gov/docs/fy06osti/39291.pdf. The table from the report which shows the land resource requirements is provided below for your convenience.

Given that there are 640 acres per square mile and dividing the capacity potential by the land area, the land requirements are 5.7 acres per MW or rounding up 3 acres per 500 kW for parabolic trough without storage. The land requirements for dish are 5 acres per MW or 2.5 acres per 500 kW. However, dish manufacturers claim they require less land and that the land remains usable for and undisturbed for other purposes. The 1 acre per 500 kW was quoted by Infinia. The land requirements for concentrating PV are 6 acres per MW or 3 acres per 500kW.

Table 3-1
Concentrating Solar Power Technical Potential

	Solar Resource Land Area, mi^2	Capacity Potential, MW	Generation Potential, GWh
Parabolic Trough, no storage < 1 % slope	5,900	661,000	1,614,000
Parabolic Trough, six hours storage < 1 % slope	5,900	471,000	1,640,000
Power Tower, six hours storage < 1 % slope	5,900	342,000	1,233,000
Parabolic Dish, < 3 % slope	11,600	1,480,000	3,371,000
Parabolic Dish, < 5 % slope	14,400	1,837,000	4,196,000
Concentrating PV, < 3 % slope	11,600	1,235,000	2,859,000
Concentrating PV, < 5 % slope	14,400	1,534,000	3,558,000

<u>HECO Companies-IR-5</u>
Reference: Tier 3 LCOE Model
Did the HECO Companies include the cost of environment assessments and/or environmental impact studies, as are or may be required in connection with State and other lands which will likely be appropriate for FiT projects, in the LCOE Model? If so, what were the costs included in the Tier 3 LCOE Model for these items?

<u>HECO Companies Response:</u>

Yes. Please review the memo provided by Perry White, Planning Solutions, titled "Feed-in Tariff Tier 3 Pricing Development: Permitting and Environmental Factors" that was distributed to the parties in an email from Rod Aoki on March 10, 2010 at 5:24 p.m. This document details the issues considered for the environmental assessments and studies. The HECO companies used the high end estimate to make a conservative assumption for permitting costs.

HECO Companies-IR-6

Reference: Tier 3 LCOE Model

Which of the following interconnection-related expenses were included in the Tier 3 LCOE Model: Interconnection Study, Interconnection Equipment, Cost of Installation, Operation and Maintenance up to transfer of the Interconnection Facilities, Costs of any Re-Locating any Interconnection Facilities, Removal of Interconnection Facilities after termination of the PPA, and Restoration of Land upon which Interconnection Facilities were installed. What was the total cost of the interconnection-related expenses included and where in the LCOE Model were these costs included? Are there any other interconnection-related costs that were not included in the LCOE Model?

HECO Companies Response:

The Tier 3 pricing included the Interconnection Requirement Study ("IRS"), the line extension, and the Cost of Installation for the SCADA and direct transfer trip. Operation and Maintenance up to the transfer of the facility should be minor and were not included. The pricing team reviewed the projects with a completed IRS that could be used for Tier 3 benchmarking. (More information will be provided on the estimated costs of IRS studies that are currently planned or in-process for projects that would be in the Tier 3 size range in the April 29th filing.) The projects reviewed to date did not include re-locating interconnection facilities, and in the HECO pricing team's opinion re-location of interconnection facilities would not be typical of a Tier 3 project. The salvage costs were not included in the cost of generation model, and therefore the cost of removal and land restoration was also not included. These costs are not well known and it is likely the salvage cost of the materials in the plant would cover most, if not all, of these costs.

The interconnection costs assumed are the same across the technologies. Please see the interconnection cost data from the March Workshop presentation below. The interconnection costs were included in the LCOE model in the CapEx input. This can be verified and seen in the input page of the worksheets distributed to the parties in an email from Rod Aoki on March 10, 2010 at 5:24 p.m.

Interconnection Costs					
1 MW		2.5 MW		5 MW	
Item	Cost	Item	Cost	Item	Cost
Interconnection Requirement Study	$ 25,000	Interconnection Requirement Study	$ 35,000	Interconnection Requirement Study	$ 75,000
SCADA and Direct Transfer Trip	$ 500,000	SCADA and Direct Transfer Trip	$ 500,000	SCADA and Direct Transfer Trip	$ 500,000
		12 kV line extension - 1,000 ft.	$ 100,000	46 kV line extension - 1,500 ft.	$ 150,000
		Transformer	$ 80,000	Transformers	$ 525,000
Total:	**$ 525,000**	**Total:**	**$ 715,000**	**Total:**	**$ 1,250,000**

HECO Companies-IR-7
Reference: HECO's Proposed Schedule FiT and HECO's Proposed PPA
HECO Companies' proposed Schedule FiT Tier 3 ("HECO's Proposed Schedule FiT") and proposed Tier 3 Feed-In Tariff Power Purchase Agreement (HECO's Proposed PPA") set forth a number of additional fees and charges, including: a Reservation Fee, an Operating Period Security, and a recurring service charge. Where in the LCOE Model are these fees included?

HECO Companies Response:

HECO does not plan to include any refundable fees or security deposits in the pricing model. As for the non-refundable fees and service charges, no recommendation has been made at this time as to whether they should be included in the pricing model or not. This matter is still under discussion and may be addressed differently for the different FIT Tiers. Please note that these fees and service charges are only a proposal at this time and are still subject to Commission approval.

HECO Companies-IR-8
How do the HECO's Companies plan to improve their grids in order to reduce and eventually eliminate the need to curtail independent power producers over time? What is the expected time schedule for these improvements?

HECO Companies Response:

It is an objective of the Companies to support a sustainable, renewable energy portfolio which considers both cost and reliability. As such, the Companies are pursuing a variety of initiatives to evaluate how to more efficiently integrate these resources to the utility systems.

While a reduction in curtailment is not the sole consideration in the integration of renewable resources, a reduction in curtailment generally could be accomplished through storage facilities, by increasing demand during curtailment periods, or by decreasing the minimum dispatch of must-run and must-take generation. The HECO Companies are currently investigating options in each of these areas, such as:

- Investigating the cost-effective use of battery energy storage options that might be useful in time shifting some of the excess energy and/or be used to reduce the reserve requirements on the conventional units;
- Attempting to increase demand during periods of low load though time of use lower rates and encouraging the use of electric vehicles, which it is hoped would increase demand through charging at those times;
- Investigating interconnections to several of the island grids though the Interisland Cable Project. There is potential to better leverage the diversity in renewable resources across a larger geographic area and increase loads during periods when curtailment typically occurs on the outer islands, such as Maui;
- Continuing to investigate changes to the operations of conventional and renewable

dispatchable units that would increase the dispatch range and achieve a lower minimum output or range of performance.

- Expanding visibility and controls at both the distribution and transmission levels (i.e. DSM, Supervisory Control and Data Acquisition (SCADA)) that will facilitate the controllability of demand to better fit the needs of the system at the time.

Active power control or curtailment to reduce production from variable resources such as wind, solar, and run of river hydro during periods of excess energy has been a tool which has allowed the interconnection of large variable generation resources on the island power systems in Hawaii and in other places in the world. ERCOT, WECC and other NERC governed bodies are also challenged with managing substantial production and non-production periods from as-available renewable resources. Because of their inter-tied grids and export markets, excess energy from an as-available facility may be exported and competitively sold to another part of the country where that energy may be utilized. However there are times in which the excess energy generation must be curtailed and/or spilled due to congestion or transfer capacity limitations imposed on the transmission lines. Thus, curtailment remains a fundamental and essential component to facilitate high penetration of variable renewable energy as well as to maintain reliability and balance in power systems. In the absence of this active power control capability, the addition of variable energy resources would have been limited to only that which could be taken or contractually limited at all times of the day; and would have precluded the addition of the existing large wind plants on the MECO and HELCO systems and the run-of-river plant on the HELCO system.

Additionally, both conventional fossil units and renewable dispatchable units, are a critical part of being able to integrate variable renewable resources because they are able to operate at reduced or part load for frequency control and load following, and also provide the basic balancing between demand and supply on the power system.

Finally, suggesting that the system needs "improvement" to eliminate or reduce energy curtailments seems to infer that there are shortcomings on a particular power system. While system modifications provide a vehicle to address curtailments in certain circumstances, generally, excess energy curtailments are simply due to the condition that demand at times is not sufficiently large to accommodate the energy being produced (including from variable renewable energy providers including roof-top-PV and other distributed generation which currently are not visible to the grid operators nor dispatchable). Even with the scheduled must-take generators (i.e. waste to energy plants, generators needed for maintaining system stability and reserves) and dispatchable must-run renewable resources at their minimums, curtailment hours still exist particularly during minimum night time hours. It is important to note that at this time, the as-available, must-take facilities which are subject to curtailment for excess energy on both the HELCO and MECO systems are not subject to economic dispatch. Energy is purchased from these facilities for the HELCO and MECO systems and is currently given a higher priority relative to other resources, including dispatchable renewable energy which may have lower energy production costs. For the island systems to attain RPS targets and attain reliable, cost-effective energy options, it is important to consider the longer term economics and interoperability of a portfolio of complementary resources.

HECO Companies-IR-9
Reference: Section 14.12 and 14.13 of HECO's Proposed PPA
List other FiT Programs in which renewable energy producers are required to execute and deliver a Security Agreement, similar to the one set forth in HECO's Proposed PPA, in favor of the utility power purchaser? Do these programs also permit the utility power purchaser to fixture filings, financing statements, and other Security Documents as the utility power purchaser deems necessary or appropriate to perfect its security interest in the facility at issue and/or project documents?

HECO Companies Response:

The Hawaiian Electric Companies object to this information request on grounds that the request is overly broad, unduly burdensome and oppressive. Without waiving these objections, the general purpose of the Security Agreement is to secure sums which may be owing to HECO under the Schedule FIT Agreement (e.g., damages). This type of provision is beneficial to both ratepayers and the utility because it helps assure that Seller obligations under the Schedule FIT Agreement are met and that ratepayers and the utility are not put in a position of having to bear costs for which they are not responsible, particularly where multiple claims are being made against the Seller. The Hawaiian Electric Companies are continuing their evaluation of these sections and will address them in more detail in their filing on April 29, 2010.

<u>HECO Companies-IR-10</u>
Reference: HECO's Proposed PPA, Sections 19.2 thru 19.4
List other FiT Programs that:
(1) prohibit a renewable energy producer from pledging, mortgaging, or granting a security interest in the facility at issue without the prior consent of the utility power purchaser,
(2) require a renewable energy producer to provide the utility power purchaser with the terms of any financing documents, and to obtain the utility power purchaser's review of and consent to the documents, and/or
(3) require a renewable energy producer to use "Commercially Reasonable Efforts to obtain Financing Documents in a form reasonably satisfactory to" the utility power purchaser, and further obligate a facility lender to make a binding commitment to the utility power purchaser that the facility lender would take no action to affect or impair the utility power purchaser's rights under the applicable PPA or FiT Agreement.

<u>HECO Companies Response:</u>

The Hawaiian Electric Companies object to this information request on grounds that the request is overly broad, unduly burdensome and oppressive. Without waiving these objections, it is neither unusual nor unreasonable for the utility to have the opportunity to consent (which consent shall not be unreasonably withheld, conditioned or delayed) to a lender who will potentially be making decisions affecting the entity holding the Seller position under a power purchase agreement. To the extent that lenders seek to step into the borrower's shoes in the event of a default, it is also not unreasonable for the contracting party (in this case, the utility) to ask for assurances in return that the lenders will not impair the utility's rights under the PPA. The Hawaiian Electric Companies are continuing their evaluation of these sections and will address them in more detail in their filing on April 29, 2010.

Response to

Zero Emissions Leasing LLC's

Information Requests

ZE-IR-108
For each utility electric system on the islands of Oahu, Hawaii, Maui, Molokai and Lanai: how much as-available renewable energy could be added to the electric system of each island without compromising electric system reliability based on the regulating capacity of the utility's must-run and dispatchable non-renewable generation taking into account any displacement of the utility's dispatchable non-renewable generation by the added as-available renewable energy generation

HECO Companies Response:

Please see the Companies response to ZE-IR-107 filed March 1, 2010 that provided a list of curtailable non-renewable generation.

The FIT Reliability Standards filing provided initial recommendations on the penetration targets for each of the islands based on existing regulating capability and dispatchable generation. A curtailment analysis was also provided which took into account maximizing renewables to displace or turn down must-run generation. These scenarios were evaluated in ways that preserved system reliability based on current experience and operational practices. Further displacement of non-renewable generation would require more in depth system analysis that may require changing existing practices and developing new operational procedures.

As the FIT resources are currently "as-available" and not dispatchable, they are not counted for providing base generation in the planning process. Also, as the performance and penetration of these resources have typically been small, the systems were typically able to accommodate small deviations in generation with reserve capacity.

With significant levels of "as-available" penetration, there are challenges managing resources as noted in the Reliability filings. Since the electric system reliability can be measured by system frequency control and regulation, the reliability can be adversely impacted by additional as-available renewable energy if that energy is highly variable. The degree to which these factors will affect frequency control will depend on the specific characteristics of the as-available generation, both individually and in aggregate. If the generation is relatively constant and predictable, there will be less impact than if the addition causes significant additional imbalance on a second to second or minute to minute basis. There are technical concerns regarding the aggregate impact of additional distributed variable generation which require additional study to quantify. This is due to issues described in the reliability filing, such as the system impact of nuisance trips during voltage and frequency disturbances and issues created by the lack of monitoring and control. Further, considering the anticipated firm, dispatchable renewable energy providers on the HELCO system, in the absence of load-growth, any additional as-available renewable energy would primarily displace purchases from these transmission-connected renewable resources and therefore would not help increase the overall level of cost-effective renewable resources. A further consideration regarding as-available generation is whether or not it is connected to the power system on the distribution level. There are technical concerns regarding the aggregate impact of additional distributed variable generation which require additional study to quantify. This is due to issues described in the Companies' FIT Reliability filing. Examples recommended for further investigation included the system impact of nuisance trips during voltage and frequency disturbances and issues created by the lack of monitoring and control.

Before committing to displacement of any existing regulating capacity, which are currently planned to meet contingencies, additional studies to establish performance criteria for as-available renewable energy generation must be performed to see if those resources can provide equivalent grid responsive replacement (in MW, VAR, inertia) for the displaced regulating capacity. The Hawaiian Electric Companies have proposed a Working Group to be established so that the appropriate studies may be identified and the assumptions vetted with the parties prior to finalizing any further analytical runs.

ZE-IR-109
For each utility electric system on the islands of Oahu, Hawaii, Maui, Molokai and Lanai: how much of the as-available renewable energy that could be added to the electric system of each island without compromising electric system reliability should the utility be obliged to purchase based on the relative costs and benefits of the added as-available renewable energy and any dispatchable non-renewable energy displaced by the added as-available renewable energy?

HECO Companies Response:

The HECO Companies are committed to adding as much renewable energy as possible without compromising system reliability or causing excess curtailment. As such, the Companies should not be obligated to purchase any amount of as-available renewable energy or other type of energy without first considering need, cost and the ability to cost-effectively accommodate the resource. It is the Companies' belief that obligating the utilities to purchase energy without regard to impacts would be inconsistent with the interests of customers and ratepayers and the Commission's directives in its Decision and Order. (See, September 25, 2009 Decision and Order at 56)

Currently, the HECO Companies have already committed to take significant levels of renewable resources through existing solicitations and initiatives. These efforts will result in dramatic increases to existing levels of renewable resources on all islands. Additional studies will need to be conducted to assess the details of operating with such higher levels of renewable generation, in particular variable renewable generation. In addition to cost considerations and reliability considerations, additional as-available energy in the absence of demand growth, such as HELCO is experiencing today, will reduce the potential sales of the existing as-available and planned dispatchable RE suppliers.

As there are many combinations of factors that can influence the ability of an electrical system to integrate as-available variable resources, it is difficult to state or identify a maximum for each island due to the dynamic nature of an electrical system. Such variables include, but are not limited to, future system loads, types of as-available renewable generation (existing and proposed), geographic location of as-available renewable generation, the operational characteristics of as-available renewable generation and the SCADA visibility and control of the as-available renewable generation. It should also be noted that an additional issue that can compromise electric system reliability is the replacement of dispatchable generation, known for its grid-support capabilities and reliability attributes, with as-available renewable generation, which is inherently dynamic in nature and has limited or not widely demonstrated grid support capabilities.

We welcome an open process through the proposed Working Group to pursue study scenarios and help in identifying and implementing solutions to allow the utilities to reliably integrate additional levels of variable renewable generation given the various generation resources (both distributed and large-scale) which could be interconnected and the system characteristics of each island grid.

ZE-IR-110
Please produce all results obtained from the General Electric Positive Sequence Load Flow (PSLF) models for the utility electric systems on the islands of Oahu, Hawaii and Maui, and all input assumptions used to obtain such results.

HECO Companies Response:

See attachments 1 and 2 for the GE reports for the Phase 1 work on Maui and Hawaii that was provided to the FIT parties on May 20, 2009. These reports are available and have been issued by HNEI and GE. They cite preliminary efforts to develop and validate a set of GE's tools to assess transmission level impacts of island systems and began with the MECO and HELCO efforts as described in these studies. However, as these models were not focused on FIT integration issues, the results of these studies are not directly applicable. Utility load flow modeling and planning tools similar to the GE PSLF and MAPS tools certainly may be tailored to assess the aggregated impact of increasing levels of PV on the grids. However appropriate assumptions and scenario-based levels must be determined. Preliminary efforts as proposed in the FIT Reliability filings provided recommendations for such follow on work with transparency in making assumptions through a Working Group process.

The HECO Companies use PSS/E (PTI) as the tool for system planning and do not have licenses to run PSLF GE models. PSS/E (PTI) is widely used in the power industry, and is a competitor to the GE PSLF product. The analytical work GE Energy is doing under contract with HNEI is described in the response to HREA-IR- 1 and HREA-IR-2. For these studies, analysis and assumptions provided by the HECO Companies were for the purpose of evaluating specific projects such as the inter-island wind project which is evaluating technical requirements to interconnect 400 MW of wind energy from the islands of Molokai and Lanai, or as in the case of the Big Island studies, future ideal scenarios envisioned by GE/HNEI. Efforts are still underway and results are not yet complete for most of the analysis, with no reports issued by the HECO Companies. As the work is partially funded by U.S. DOE, once the project results are complete, publically available final reports should be made available by HNEI.

For HECO, the GE scenario-based analyses serve to inform the evaluation process for future RPS projects such as the inter-island wind project and will require further life-cycle cost evaluation and detailed system analysis based on actual designs and performance specifications which will have to be negotiated competitively with prospective developers. The negotiation process and any follow-on analysis would then be considered business sensitive and confidential.

More importantly, for all studies utilizing GE analysis to date, the assumptions and scenarios are not appropriately tailored to address FIT distribution impact assessments. The impacts of distributed FIT eligible resources were not included in any of the scenario analyses completed to date. For the follow-on detailed analysis as recommended in the FIT Reliability filings and in the response to ZE-IR-108, existing system and distribution modeling need to be completed based on performance specifications that can be implemented onto the system today.

Maui Electrical System Simulation Model Validation

Prepared for the

U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability
Under Award No. DE-FC-06NT42847
Task 9 Deliverable –
Baseline Model Validation

By

GE Global Research
Niskayuna, New York

And

University of Hawaii
Hawaii Natural Energy Institute
School of Ocean and Earth Science and Technology

November 2008

Acknowledgement: This material is based upon work supported by the United States Department of Energy under Award Number DE-FC-06NT42847.

Disclaimer: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Legal Notices: This report was prepared by General Electric Company (GE) as an account of work sponsored by the Hawaii Natural Energy Institute (HNEI), Maui Electric Company (MECO) and Hawaiian Electric Company (HECO). Neither GE, nor HNEI, nor HECO, nor MECO, nor any person acting on behalf of either:

1. Makes any warranty or representation, expressed or implied, with respect to the use of any information contained in this report, or that the use of any information, apparatus, method, or process disclosed in the report may not infringe privately owned rights.

2. Assumes any liabilities with respect to the use of or for damage resulting from the use of any information, apparatus, method, or process disclosed in this report.

Data was provided to GE by HECO and MECO for the purpose of operating under the Maui Grid Study contract. These data were used to build the models and are summarized in this report.

Table of Contents

1. Introduction

The Maui Grid Study is a joint study by Hawaiian Electric Company (HECO), Maui Electric Company (MECO), the Hawaii Natural Energy Institute (HNEI) and the General Electric Company (GE). It is one of the components of the Hawaii Distributed Energy Resource Technologies for Energy Security project.

The primary objective of this study is to develop and calibrate dynamic and production cost models for the MECO electricity grid. This is the first set of steps in an activity designed to help MECO identify technologies or operating strategies that will enable the system to manage higher amounts of as-available renewable energy. These models were validated against a base year and will be used to evaluate power system expansion scenarios for the island of Maui. This program began in January 2008 with the data acquisition and model development. This deliverable highlights the validation of the power systems model for the island of Maui.

In order to ensure the model accurately captures MECO's present system operation, the model was calibrated and validated against historical data. However, some of the operating practices that are presently in place were not in place in 2007. In order to ensure the model is useful for analysis of future scenarios, the present operating conditions were generally modeled, while only some historical operating conditions were captured. Significant iteration with the HECO/MECO team was needed to ensure the model accurately captured MECO system operation to a level of fidelity sufficient for the next phase of this study (scenario analysis of the future MECO system). Weekly meetings were organized to allow the model development and validation team to present the results from each model. Questions were asked of the HECO/MECO team to clarify system-operating practices. Based on their responses to these questions, and their inputs and directions based on questions that HECO/MECO raised, the GE team revisited the model each week, implemented the necessary changes, and presented the latest results at the following meeting. This document represents the Deliverable for Task 9, the Baseline Model Validation results. The modeling, validation, and management team is comfortable with the level of accuracy for both the GE PSLF™ and GE MAPS™ models of the MECO system for the application of these tools to system scenario analysis.

This document is intended to present the validation of databases created in GE MAPS™ and GE PSLF™ for the analysis of the electrical systems of MECO. The databases were compiled based on the data provided by HECO and MECO. These data were described in the Task 8 Deliverable, "Maui Electrical System Model Development: Data and Assumptions," the report on System Model Development. Some of the models were further improved based on the input provided by HECO and MECO after the Task 8 Deliverable was submitted. After HECO and MECO have reviewed this document, an exchange will be held to discuss the model validation and scenarios to be considered in the next task of the project.

A final comment is appropriate. This effort was primarily funded using HECO funding as part of the larger, related project that is funded by DOE. As a result, some information is considered proprietary by the utility and is presented here in this report as qualitative conclusions, although quantitative information has been presented to the utility.

2. Model Validation

The Maui grid is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. From a control perspective, the load and the wind power production are the primary independent variables – the drivers to which all the short-term controllable elements in the power system must be positioned and to which they must respond. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and nature) of load served by the system. The performance of the power system is highly dependent on the ability of the system to accommodate changes and disturbances while maintaining quality and continuity of service to the customers.

The modeling exercise is aimed at capturing technical aspects of challenges related to regulation, frequency control, load following and unit commitment within the transmission system capabilities associated with the present infrastructure, including intermittent resources such as wind generation. The quantitative analysis covered a broad range of timeframes, including:

- Seconds to minutes (regulation and frequency control) – Dynamic simulation,
- Minutes to hours (load following, balancing) – Dynamic simulation, and
- Hours to days (unit commitment, day-ahead load forecasting and schedules) – Production cost simulation.

There are several timeframes of variability, and each timeframe has corresponding planning requirements, operating practices, information requirements, economic implications and technical challenges. Much of the analysis in the first phase of the project was aimed at quantitatively evaluating the impact of existing MECO assets, including wind resources, in each of the timeframes relevant to the performance of MECO's power system. In the longest timeframe, planners look several years into the future to determine the infrastructure requirements of the system based on capacity (or adequacy) needs. This timeframe includes the time required to permit and build new physical infrastructure. In the next smaller timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this timeframe, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. This is the shortest timeframe in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made the day ahead are implemented and refined to meet the changing load. In the shortest timeframe, cycle-to-cycle and second-to-second variations in the system are handled primarily by automated controls. The system's automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e., are detected at the generating plant or substation). In addition, a subset of generators provide regulation by following commands from the centralized Automatic Generation Control (AGC), to meet overall system control objectives including system frequency.

In the context of MECO, the infrastructure has been modeled at different levels:

- Transient modeling, in the seconds-to-minutes timescale, to validate stability and transient performance of the island grid, and
- Production cost modeling, in the hours-to-days timescale, to determine the operating economics of the power system.

The production model was developed in GE MAPS™. The results of the production cost model were compared to the 2007 historical operating conditions. The comparison is summarized in this report. The dynamic model was developed in GE PSLF™. The AGC model was developed to represent the MECO AGC. Three "windows" of system operation were chosen and the AGC model was calibrated and validated against these windows. This type of simulation is referred to as a long-term dynamic simulation. Additionally, transient stability simulations were performed. This included simulating load flows and contingencies in GE PSLF™ to ensure the model represented actual system behavior

2.1 Production Cost Modeling (GE MAPS™ analysis)

Production cost modeling of the MECO system was performed with GE's Multi Area Production Simulation (GE MAPS™) software program. This commercially available modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. This tool was used to simulate the MECO production for 2006. Ultimately, the production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

The overall simulation algorithm is based on standard least-marginal-cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before higher marginal cost generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum regulating reserve, and stability limits, as well as the physical limitations and characteristics of the power plants. Significant input has been received from HECO and MECO, and multiple model iterations have been performed, to ensure that all physical, contractual, and reliability requirements were met.

2.1.1 Model Data and Assumption

In order to characterize the operation of the MECO system in GE MAPS™, general operating assumptions were needed. It was understood by both GE and HECO/MECO that the actual operating practices vary depending on unique system events and conditions, such as the present and anticipated wind power production, the load level, the number and types of units on outage, etc. The data used in the model are outlined in the Deliverables for Tasks 6 and 7. The model data and assumptions are outlined in the Deliverable for Task 8.

To briefly summarize the Task 8 Deliverable, some of the inputs to the GE MAPS™ model are summarized below:

- Sum of hourly generation as the load profile.

- Unit characteristics, such as heat rate curve over the entire operating range. Maximum power point, minimum power point, planned and forced outages rates, regulating reserve capability, and emissions rates.
- Hourly wind power production.
- Hourly HC&S production.
- System and unit constraints.
- System losses due to transmission.
- General operating assumptions (described later in the report).

The unit-by-unit characteristics are summarized in the GE MAPS™ model. The incremental heat rate values were compared to the MECO "ABC Heat rate Curves" to verify that the conversion was performed accurately. The fuel cost data are an input to the GE MAPS™ model. These data were provided by MECO (see Table 1).

Table 1: MECO thermal plant fuel cost data ($/MMBtu) from "Power Supply Reports ('07)_031708mm.xls".

	RESIDUAL	DISTILLATE
1/1/2007	8.14	14.69
2/1/2007	8.35	16.25
3/1/2007	8.01	15.09
4/1/2007	8.43	15.62
5/1/2007	8.78	15.96
6/1/2007	8.97	17.18
7/1/2007	9.91	16.93
8/1/2007	9.91	17.52
9/1/2007	10.19	18.12
10/1/2007	10.05	17.51
11/1/2007	10.38	17.58
12/1/2007	11.32	18.92

In order to characterize the operation of the MECO system in GE MAPS™, general operating assumptions were made. It was understood by both GE and HECO/MECO that the actual operating practices will change depending on unique system events, such as the present and anticipated wind power production and load condition, as well as the number and types of units on outage, etc.

The following general modeling assumptions were made:

- M14, M15, M16 were modeled as operating in dual-train combined cycle mode.
- M17, M18, M19 were modeled as operating in dual-train combined cycle mode from 6 am to 10 pm.
- M17, M18, M19 were modeled as operating in single-train combined cycle mode from 10 pm to 6 am.
- HC&S was modeled as operating on the following schedule:
    - 9 MW from 9 pm to 7 am, and 13 MW from 7 am to 9 pm, on Monday through Saturday; and 9 MW on Sunday.

- Kaheawa Wind Farm (KWP) was modeled based on 2007 hourly wind power production data (post-historical curtailment).
- K1 was modeled as operating from 6 am to 11 pm.
- K2 was modeled as operating from 7 am to 10 pm.
- M4, M5, M6, M7, M8 and M9 were modeled as being available from 7 am to 10 pm.
- The regulation reserve requirement was modeled as:
    - 6 MW plus half the power production of the Kaheawa wind farm. The regulating reserve requirement calculation was changed to a new methodology in 2008.
    - M4, M5, M6, M7, M8, M9, M10, M11, M12, M13, M14, M15, M16, M17, M18, and M19 were modeled as the units capable of providing regulation.
- There was no power production from Makila hydro plant in 2007; therefore, no power production from the hydro plant was included in the model.
- Outages were simulated in MAPS based on 2007 historical outage duration by unit. In future analyses it is likely that the 5-year average outage data, by unit, would be implemented in the model.
- The general commitment order was obtained from MECO as: K3, K4, M14/15/16, M17/18, K1, K2, M10, M19, M11, M12, M13, M8, M9, M4, M6, M1-3, X1, X2, M5, M7
    - M10, M11, M12, and M13 are interchangeable in commitment order.
    - M4 and M6 are lower in the commitment order than M8 and M9 due to the limit on the operating hours.
    - M5 and M7 are lowest in the commitment order due to the air permits on NOx emissions.
    - M1, M2, and M3 interchangeable in commitment order.
    - X1 and X2 are interchangeable in commitment order.

The incorporation of these system constraints and assumptions increased the accuracy of the model with respect to the 2007 operating year. This allowed the project team to compare the model results to the historical data in order to gain comfort in the implementation of the MECO system data into the GE MAPS™ model.

2.1.2 Results of the Production Cost Model Analysis

Based on the validation objectives developed at the onset of this task by the HECO/MECO/GE team, the results of the model were compared to historical data. The GE MAPS™ hourly production data, by unit, and a summary table, outlining the annual unit-by-unit energy production, annual production cost, annual emissions, annual fuel consumption, etc., were obtained from the model.

One of the qualitative methods for comparing model results to historical data is to visually compare the hourly generation, by unit type, to historical data over a long period of time (see Figure 1). The GE MAPS™ model predicted hourly energy production similar to the historical 2007 production. Some of the discrepancy between the two figures can be attributed to unit outages occurring in MAPS that did not historically occur in the same time frame. Additionally, any operator intervention is not captured in the GE MAPS™ model. Furthermore, discrepancies between the historical system operation and the model results will be discussed later in this section. This qualitative comparison allowed the project team to gauge how accurately some of the operating constraints were being implemented in the model.

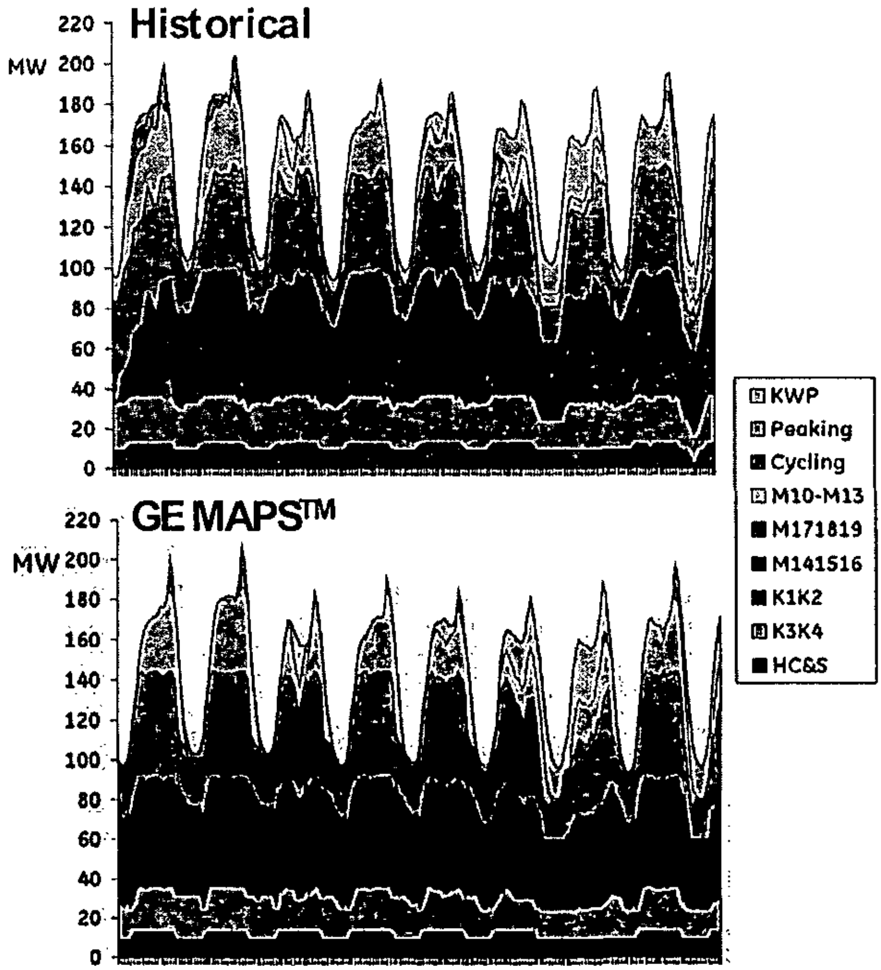


Figure 1: GE MAPS™ model results compared to historical hourly generation data for 200 hours, starting November 26, 2007 and ending December 4, 2007. The MAPS model Did not simulate the exact outage events as they historically occurred in 2007.

A number of quantitative methods for comparing the GE MAPS™ model results to the historical data were performed. The first method considered the annual energy production, by unit type. Since most production cost models consider units of similar type and heat rate as interchangeable, comparisons are generally made on a unit-type basis. The 2007 historical energy production was chosen as the benchmark year. There are notable differences between the way MECO operated the system in 2007 and the way in which it is presently operated. Both some of the present operating strategies and some of the former operating strategies were modeled in GE MAPS™; therefore, a very close comparison to the 2007 historical year may not necessarily reflect how accurately the model would predict system operation while analyzing scenarios for subsequent years (i.e., using post-2007 operating practices only). Where reasonable, the project team modeled some of the operating practices in 2007 in order to demonstrate the validity of the MAPS model to a benchmark year. The annual energy production, by unit type, is shown for both the 2007 historical MECO operation and the MAPS model in Figure 2.

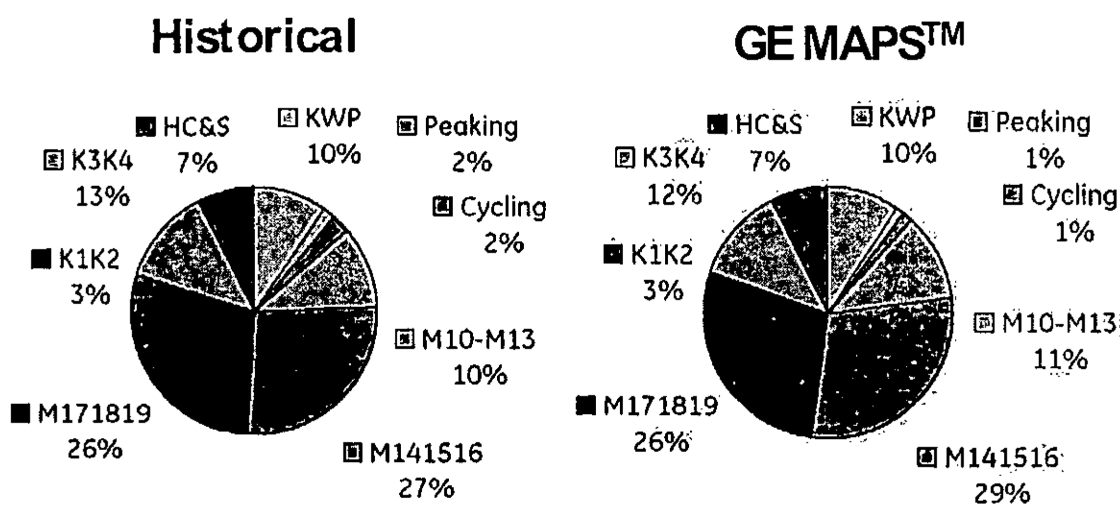


Figure 2: Comparison of the annual energy production (MWh), by unit type, between the Historical 2007 Maui energy production and the GE MAPS™ model simulation. Note that The Cycling units refers to M4, M5, M6, and M9, and the Peaking units refers to X1, X2, M1, M2, M3, M5, and M7.

Recognizing the limitations of the model, the project team was satisfied with the level of fidelity observed on a unit-by-unit basis. The annual energy production, by unit type, compared within 1% of historical energy production. Later in this section, the differences between the model and the historical data are discussed in further detail.

The second quantitative method for validating the production cost model was a comparison between the average MECO system heat rate, based on 2007 historical data, and the system heat rate obtained from the GE MAPS™ model. The heat rate is calculated as the total fuel consumption on a fuel-type basis per kWh produced by those units.

Based on the results of the MAPS simulation, the heat rate was ~5% less than the historical MECO system heat rate. This indicates that GE MAPS™ overestimates the overall system efficiency by ~5%; similar to the level of fidelity observed in the HECO/MECO production cost simulations.

The model results captured the historical energy production, by unit type and the historical system heat rate, within 5%. Some of the discrepancy between the model results and the historical 2007 results can be attributed to the following factors:

- Intra-hour variability of wind/load was not captured in the hour-to-hour simulation tool. Natural imperfect dispatch of generation due to the present wind production and the wind power production trend was not captured in the model.
- The amount of regulating-up reserve available to address the decrease in wind production and increase in load varies within an hour. In the hour-to-hour simulation, the inter-hour changes in regulating reserve were not captured.
- Changes in the regulating reserve requirement may lead or lag the changes in the load and actual wind power production. For example, the amount of reserve also depends on the load level and the anticipated rate of change in load. Additionally, if the wind power is steady, MECO may decide to decrease the reserve requirements. These decisions are made at the discretion of the operator and could not be systematically captured in the model.
- After starting some units, they do not count towards the regulating reserve requirement until a specific period of time has passed. The model counts this unit in the regulating reserve requirement once it has been started.
- Differences in commitment/dispatch during outages were not captured. For example, K1 or K2 was operated as baseload when K3 or K4 was on outage.
- Temporary unit de-ratings occurred during 2007 historical operation. These de-ratings were not captured in the model.
- A detailed list of the unique operating conditions, generally not captured in production models, is provided in Docket No. 2006-0387. For example, performance tests were performed on M18 in 2007, M13 was only in operation for half of 2007 and returned to operation on July 9, 2007, and biodiesel fuel testing was performed on some of the diesel-fired units in 2007.
- HC&S was modeled on a fixed schedule, not on the actual historical production from 2007. This was done to ensure the validity of the model for scenarios.

2.1.3 Conclusions of the Production Cost Modeling

The project team agreed that the production cost model of the MECO system accurately captured the energy production, by unit type, within 1% and the system heat rate within 5%. The GE team is satisfied with the level of fidelity of the production cost model and recognizes that some of the discrepancy between actual historical production and simulate production can be attributed to a list of factors described above. The project team believes that the use of this tool to analyze system scenarios on the MECO system is appropriate for future phases of the project

2.2 Transient Stability and Long-Term Simulations (GE PSLF™ analysis)

Transient and long-term dynamics simulations are used to estimate system behavior (such as frequency) during wind power fluctuations and system events. In combination with good engineering judgment with the understanding of the limitations of the model, this type of modeling can be used to understand the impact of transient operation of different generators on system frequency in a seconds timeframe, and can be used by utilities to ensure that the system frequency remains stable and within acceptable limits during critical operating conditions. For example, if wind power production suddenly decreases due to a sudden calming of wind in the area, another generator must increase its electricity production as quickly as the windfarm decreased its production. Depending on how fast the generator increases its production, the system frequency will deviate from 60 Hz. The dynamic simulation tool can be used to estimate the frequency excursion associated with this type of an event.

Long-Term Dynamic Simulations were performed for MECO's grid using GE's Positive-Sequence Load Flow (GE PSLF™) software. Second-by-second load and wind variability were used to drive the full dynamic simulation of the MECO grid for several thousand seconds (approximately one hour).

2.2.1 Load Flow Database conversion

The Transmission Planning Division of HECO provided load-flow databases in PSS/E format. The PSS/E datasets were converted to GE PSLF™. The comparison of GE PSLF™ results and PSS/E results was adequate and presented in the Task 8 deliverable.

2.2.2 Steady State Contingency Simulations

2.2.2.1 N-1 Contingencies in the 69 kV System

Based on the breaker locations in the single-line diagram of the MECO 69 KV system, an N-1 outage of all 69 KV lines was considered for both minimum and peak load cases. Constant power loads, generator terminal voltage control, no tap changer action and no automatic cap switching were assumed. The list of lines considered for the N-1 contingencies is given in Table 2.

Table 2: Contingency list of lines.

Outage name	Outage description
line_1	Line MAALAEA 69.0 to LAHAINA 69.0 Circuit 1
line_2	Line LAHAINA 69.0 to PUUKA 69 69.0 Circuit 1
line_3	Line LAHALUNA 69.0 to PUUKB 69 69.0 Circuit 1
line_4	Line LAHAINA 69.0 to LAHALUNA 69.0 Circuit 1
line_5	Line MAALAEA 69.0 to KWP 69.0 Circuit 1
line_6	Line LAHAINA 69.0 to KWP 69.0 Circuit 1
line_7	Line MAALAEA 69.0 to LAHALUNA 69.0 Circuit 1
line_8	Line MAALAEA 69.0 to WAIINU 69.0 Circuit 1
line_9	Line MAALAEA 69.0 to PUUNENE 69.0 Circuit 1
line_10	Line PUUNENE 69.0 to KANAHA69 69.0 Circuit 1
line_11	Line KANAHA69 69.0 to PUKLN69 69.0 Circuit 1
line_12	Line KULA 69 69.0 to PUKLN69 69.0 Circuit 1
line_13	Line KEALAHOU 69.0 to KULA 69 69.0 Circuit 1
line_14	Line MAALAEA 69.0 to KEALAHOU 69.0 Circuit 1
line_15	Line MAALAEA 69.0 to KIHEI 69.0 Circuit 1
line_16	Line KIHEI 69.0 to WAILEA 69.0 Circuit 1
line_17	Line WAILEA 69.0 to KEALAHOU 69.0 Circuit 1

2.2.2.1.1 Minimum Load Conditions

The maximum and minimum per unit bus voltages for all contingencies during minimum load conditions were evaluated and modeled, where necessary. This also includes the maximum per unit branch loading for all contingencies during minimum load conditions. One-line diagrams of the base case and the contingencies are also developed. No salient overloading or low voltage problems were observed for minimum load conditions, in line with collected information of the MECO system.

2.2.2.1.2 Peak Load Conditions

The maximum and minimum per unit bus voltages for all contingencies in the peak load case were also modeled and evaluated. Maximum per unit branch loading for all contingencies during peak load conditions and one-line diagrams of the base case and the contingencies were also developed.

The pre-contingency load flow during peak load conditions demonstrate low voltage conditions in the radial system between PUKLN69 and Hana. Any contingencies due to a line outage in the 69 kV system between Maalaea and PUKLN69 lead to either severe under voltage conditions in the radial 23 kV system to Hana or to voltage collapse.

Voltage collapse in this long 23 kV radial system was observed in N-1 outage of lines PUUNENE-KANAHA69 (line_10) and MAALAEA-KIHEI (line_15). Load flows did not solve with constant power load characteristics.

The voltage issues observed in the 23 kV system to HANA are in line with the information shared by MECO and HECO during the weekly discussions. Under system conditions that result in low voltages in Hana, MECO operators start small diesel units close to Hana.

2.2.2.2 Critical Contingencies

In addition to the N-1 contingency analysis of all 69 kV transmission lines, further analysis was performed based on the list of critical cases provided by MECO and HECO (Table 3).

Table 3: List of critical cases.

Outage name	Outage Description	Remarks
fnl-crtcase-01	Lost of MPP-Waiinu line(39-636)	line_8
fnl-crtcase-02	Lost of MPP-Kihei line (39-35)	line_15
fnl-crtcase-03	Lost of MPP-Puunene (39-402)	line_9
fnl-crtcase-04	Lost of Waiinu tie transformer (636-236) and Lost of Puunene tie transformer (4-4002)	transformer outages (N-2)
fnl-crtcase-05	Lost of MPP-Lahaina (39-34) and Lost of KWP-Lahaina (97-34)	line_1 & line_6 (N-2)
fnl-crtcase-06	Lost of MPP-Kealahou (39-655) and Lost of MPP-Kihei (39-35)	line_14 & line_15 (N-2)
fnl-crtcase-07	Lost of KPP-Kanaha 1,2,3 (200-202,1,2,3)	lines in 23 kv system
fnl-crtcase-08	Lost of Waiinu-Wailuku 23 (236-3)	line in 23 kv system
fnl-crtcase-09	During minimum load, lost of KPP (K3 and K4)	generator outage

The first eight critical cases occur during peak load conditions, whereas the ninth case is during the minimum load conditions. The first three cases are identical to N-1contingency cases considered in the previous section. The corresponding contingency cases are shown in the remarks column. Case 4 is an N-2 outage of transformers, and cases 5 and 6 are N-2 outages of lines. Cases 7 and 8 are N-1 outage of lines in the 23 kV system.

Case 9 is loss of K3 and K4 units at KPP during minimum load conditions. The total amount of lost generation due to the loss of units K3 and K4 is re-dispatched on the three CT units in service during minimum load conditions, which are M14, M16 and M17. This is associated with priority levels in regulation function of the AGC application in EMS. Each of the three units picks up a fraction of the total lost generation, proportionally to the amount of its reserve. The percentage of the lost generation each of the three units picks up is as follows: M14 27%, M16 27% and M17 46%.

The maximum and minimum per unit bus voltages for all critical cases were evaluated as were the maximum per unit branch loading for all critical cases and the one-line diagrams of the base case and the contingencies. Cases 2 and 6 did not converge due to low voltages in 23 kV radial system to Hana, as described in the previous section.

2.2.3 Dynamic Contingency Analysis

2.2.3.1 Critical Clearing Times

Dynamic contingency analysis was performed on the critical cases provided by MECO (Table 3). According to the information provided by MECO, typical clearing times for zone 1 faults are between 6 to 9 cycles, and typical clearing times for zone 2 faults are 20 to 50 cycles, depending on the line. Based on this information, four clearing time combinations were chosen for the dynamic contingency analysis

Angle stability is maintained in all critical cases for the first three clearing-time combinations. The last clearing-time combination (150ms-833ms) leads to loss of synchronism for the critical cases 1,2,3,5 and 6. Critical case 6 leads to very low voltages in the radial system between PUKLN69 and Hana.

Loss of KPP in case 9 leads to a minimum frequency of around 58.5 Hz and results in under-frequency load-shedding operation. Loads at KIHEI B, PUKLN A, LAHAINA1 and NAPILB12 (11.6MW) trip at 58.7 Hz. Many other loads would trip at 58.5 Hz.

2.2.3.2 Definition of Contingencies and Clearing Times

Based on the critical clearing-time calculations of the previous section and after further consultation with MECO and HECO, contingency cases were chosen and analyzed. Critical case 2 does not present transient instability. However, even though the simulation reaches a stable steady state after the fault, the system is likely to evolve to significant load disconnections due voltage collapse. In the transient simulations it can be observed that reactive power and the field current in MPP units are high and sustained for many seconds. There is significant risk of these units experiencing reduced field current due to over-excitation limiter (OEL) operation and consequently further reducing voltages. In case OEL limiters are not available in the units, the units may trip on over-excitation protection. This situation is also aggravated by the OLTC operation that tends to increase the load consumption of active and reactive power during low voltage conditions in the 69 kV system. Critical case 6 does not present transient instability, but would result in voltage collapse.

2.2.4 Governor/Turbine Models

Historical data of a fault at a 23 kV system on March 15, 2008 was provided to verify that the proposed governor models are representative of the performance of the different turbines. The event was recorded on the MECO system on March 15, 2008.

The data (unit power output) is sampled every 4 seconds. The sampling data are less than optimal for capturing the dynamic performance of governor response in detail. The steady state and slow dynamics response of the governor models were improved based on the historical data.

A frequency excursion similar to the EMS recorded signal was imposed to the governor and generator models of the different units in service. The simulated electrical power was used to compare the performance of the model and the recorded data.

Modifications were made to the database reported in the Task 8 Deliverable, mostly on droop settings. Most salient changes are:

- Unit K4 is less responsive than initially reported (governor with 10% droop). Due to 4 second sampling data it is not possible to differentiate between accelerating power and potential operation with dead band. It is evident, however, that there is no significant change in steady state power output during operation at 0.8 Hz above nominal. This unit will be assumed not to perform any significant contribution to primary frequency control. The same assumption will be made for K1, K2 and K3.
- The droop of unit M6 was increased from initially assumed 4% to 5.5% (5.6 MW base). The same will be used for M7 and M9.
- The droop of unit M11 was increased from initially assumed 4% to 4.5% (11.5 MW base). The same will be used for M11.
- The droop of unit M13 was increased from initially assumed 4% to 5.5% (11.5 MW base). The same will be used for M12.
- The droop of unit X2 was increased from initially assumed 4% to 10% (2.5 MW base). The same will be used for X1.

2.2.5 Steam Turbines on Combined Cycle Plant

Based on historical data sets for AGC validation, the models of the steam turbines in combined cycle were modified from previously reported models. System frequency, CTs and ST power output recorded on February 11 2008 were modeled. The ST output smoothly follows CT operation. At the time the frequency reaches 59.9 Hz, there is no transient increase of ST power. Similar behavior is observed in other combined cycle (M17, M18 and M19) and in other periods of recorded data. It can be concluded that both combined cycles operate with steam turbine admission valves fully open. The parameters for these models are different if the heat recovery steam generator has one or two CTs in service.

2.2.6 AGC Model Improvement

Different windows of historical data were evaluated with MECO and HECO. The list of data periods is presented in Table 4. The three windows highlighted in yellow were selected for the purpose of improving the AGC model. The main and challenging objective of this section is to understand the natural response of the system without operator action in the time frame of minutes, where AGC is most relevant.

Table 4: List of windows for AGC model improvement.

Date	Time	General Conditions	Notes
1/19/2008	0830-1030	Morning Ramp	M19 not on AGC while being step loaded up during event
2/3/08	2100-2300	High Load	Unit shut down during KWP drop. Good wind power fluctuation Modest frequency fluctuation M12 seems to be manually ramping down during relevant part of the recording HC&S does not seem to respond with droop, origin of power variations is unknown
2/6/08	0900-1100	After Morning Ramp	Units Started. - Good wind power fluctuation Considerable frequency fluctuation. Seems to trigger assist mode in AGC M10 and M11 seems to react to AGC assist mode request.M11 seems to be limiting (operations commented the fact that due to torsional concerns the units is limited) Various unit starts after frequency drop
2/7/08	0430-0630	Low Load/Morning Ramp	Units started late in event. Good wind power fluctuation Modest frequency fluctuation KPP seems to be manually ramping up during relevant part of the recording
2/11/08	1630-1830	High Load	Units started late in event. -Good wind power fluctuation Modest frequency fluctuation M13 seems to be manually ramping up during relevant part of the recording. Hard to differentiate from "natural system" response
2/11/08	2000-2200	After Peak	Good wind power fluctuation Modest frequency fluctuation M10, M11 and M13 seem to shortly react to AGC assist mode request K2 and HC&S seem to respond to manual operation
2/29/08	0430-0630	Morning Ramp	Fast Drop off, units started Window was provided earlier for validation Good wind power fluctuation Significant frequency fluctuation CTs are only units reacting to AGC request K3 and K4 manually pick up power Several units manually started outside box
5/1/08	1245-1315	Loss of HC&S	HC&S drops more than 15 MW in about 100sec. Comparatively fast frequency drop with UFLS operation. AGC seems to enter assist and emergency modes. M5 response is reducing power before the event without clear reason.

The block diagram of the AGC model was already presented in the earlier report. The historical data were used to set or confirm the parameters of the AGC model. The priority levels of the different units on AGC are presented in Table 5. Parameters of PSLF models were modified to better represent the behavior of the actual system. Several iterations were done to tune the parameters in a way that had acceptable results with the same model for three selected windows.

Table 5: Units under AGC control and priority levels.

Bus	Unit	ID	ID	Priority
106	MGS-458	4	M4	2
106	MGS-458	5	M5	3
106	MGS-458	8	M6	3
107	MGS-679	6	M7	3
107	MGS-679	7	M8	3
107	MGS-679	9	M9	3
108	MGS-1011	0	M10	2
108	MGS-1011	1	M11	2
109	MGS-1213	2	M12	2
109	MGS-1213	3	M13	2
301	CT-1 M14	1	M14	1
302	CT-2 M16	2	M16	1
304	CT-3 M17	4	M17	1
305	CT-4 M19	5	M19	1
303	ST-1 M15	3	M15	
306	ST-2 M18	6	M18	
101	KGS-1	1	K1	Basepoint
102	KGS-2	2	K2	Basepoint
103	KGS-3	3	K3	Basepoint
104	KGS-4	4	K4	Basepoint

2.2.6.1 Window 02/29/2008

The project team selected the 02/29/2008 validation window as the first window to validate. In this window, the units initially in service are:

- Wind Farm.
- K3 and K4 (did not respond to frequency fluctuations).
- M14, M16, M15, M18 and M19. M16 power output is flat as the recording is from before the controls upgrade.
- HC&S (did not respond to frequency fluctuations).

The main disturbance to the system is the wind power fluctuation that was imposed in the simulation. CTs are performing all regulation. Frequency excursions do trigger a few normal to assist mode transitions in the AGC. After the shown data, units were manually started. This window assisted the project team in setting AGC regulation gains for ACE and ACE integral as well as pulsating logic for CTs.

2.2.6.2 Window 02/11/2008

The project team selected the 02/11/2008 validation window as the second window to validate. In this window the units initially in service are:

- Wind Farm with significant variations.
- K2, K3 and K4. K2 was manually ramped down..
- M10, M11 and M13. Units are very responsive.
- Both combined cycles are in service. M16 responds to AGC regulation requests.

- HC&S. Generation did not seem to respond to frequency. The power output also had some oscillations that were most likely related to steam generation/use in the plant.

The main disturbance to the system is the wind power fluctuation that was imposed in the simulation. HC&S was also imposed in the simulations because the fluctuations of the power output cannot be controlled directly by the MECO operators. CTs and large diesels performed regulation. Frequency excursions trigger a few normal to assist mode transitions in the AGC.

Unlike the prior window, the large diesels were in service (M10, M11 and M13). These units are set to priority level 2 in the AGC and operate in Assist/Emergency Mode. It can be seen from the recording that once the frequency error is large enough to cause a normal-to-assist transition, these units react aggressively to recover system frequency. The AGC parameters associated with Assist mode and the pulsating logic of M10, M11 and M13 were improved, based on this recording. In the recording, M10 reacts somewhat differently than M11 and M13. This difference was discussed with the HECO/MECO team. There is no known reason for the differences. The most relevant characteristics of the response are similar among units and well represented in the proposed simulation model.

2.2.6.3 Window 05/01/2008

The project team selected the 05/01/2008 validation window as the third window to validate. In this window the units initially in service are:

- Wind Farm with modest variations.
- K2, K3 and K4 were manually operated.
- M1, M2 and M3. The sum of the three units was provided in the recorded data. These units were ramped up manually.
- M5. The power output does not fully respond to expected regulations request.
- M10, M11, M12 and M13. Units are very responsive.
- X2. Unit was manually ramped up.
- M16 was out of service; all other units in combined cycles were on line.
- HC&S. Dropped about 20 MW in about 150 seconds

The main disturbance to the system is HC&S power reduction. The 58.7 Hz UFLS stage operated. In the simulation, HC&S and units manually operated were imposed.

There are a few challenges associated to this window:

- HC&S switched from exporting to importing power during the window. After the HC&S switched from exporting to importing, only 1-min data were available. Most of the system dynamics are exercised in less than a 100-second period, where HC&S power drops from +7 to –7 MW. During this period, there are insufficient measurements to characterize the HC&S variation. Additional data points were added to the recorded measurements, assuming that HC&S decreased power production at a constant MW/sec rate until it reached its lowest value. This assumption is closer than assuming linear interpolation between every 1-minute sample.

- Many units reacted about 5 to 10 seconds before HC&S dropped, causing these units to increase power production (i.e., they appeared to "anticipate" HC&S's dropping out). In discussions with MECO/HECO, it was confirmed that small synchronization inaccuracies between signals could be expected. This result had a significant effect in the frequency excursion observed in this window. These synchronization inaccuracies were less relevant for slower frequency excursions observed in previous windows.
- M12 and M13 increased power before the 100 sec in recordings. The frequency at that time was not significantly off nominal to justify this power increase in these units.
- M11 does not seem to modify power according to an AGC request. It can be seen that the unit reduced power at around 400 sec even though the frequency is still below nominal after the event.

This historical window did not necessarily help in improving the simulation model, but showcased the model's ability to recreate this event within the mentioned limitations.

2.2.7 Conclusions of the Dynamic Modeling

Various aspects of the system behavior were addressed with PSLF modeling. The load flow database was successfully converted from the HECO planning tool. The steady-state contingency analysis of the system presented conditions with voltage challenges in the 23 kV radial system out of Pukalani. These simulation results were confirmed by HECO/MECO as similar challenges in the actual system operation. Transient simulation models of fast system events (faults and generation trips) were also setup. Critical events were simulated as a baseline for future scenario analysis. To the extent possible using available data, governor model parameters were improved based on historical data of 03/15/2008. The validation windows of historical data were used to tune the AGC model parameters. The resulting system model (AGC, governors, generators, network, etc.) captures the relevant dynamics of the actual system in the recorded data. The project team believes that the fidelity of these dynamic models is of sufficient quality to be used in the subsequent phase of this study.

Summary Report on Stakeholder Workshop

Prepared for

U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability

Under Award No. DE-FC-06NT42847
Task 1. Deliverable #2 –
Summary Report on Stakeholder Workshop

By

GE Global Research
Niskayuna, New York

And

University of Hawaii
Hawaii Natural Energy Institute
School of Ocean and Earth Science and Technology

November 2007

Acknowledgement: This material is based upon work supported by the United States Department of Energy under Award Number DE-FC-06NT42847.

GE Global Research

Hawaii Roadmap Phase 2

Strategic Energy Roadmap for the Big Island of Hawaii

A Presentation of the Transportation and Electricity Modeling Analysis and Results,
and
A Summary of the inputs and outcomes of the Stakeholder Summit

Delivered to:
Richard Rocheleau, Director
Hawai'i Natural Energy Institute
1680 East-West Rd, Post 109
Honolulu, HI 96822
Phone: 808-956-8346
e-mail: rochelea@hawaii.edu

Technical Contact at GE Global Research:
Devon Manz
Electric Power and Propulsion Systems Lab
One Research Circle, Niskayuna, NY, 12309
Phone: 518-387-7684
FAX: 518-387-7592
e-mail: manz@ge.com

Revision Date: October 26 2007
GE Research 5125.022

Table of Contents

Background

Hawaii must make decisions about its energy future. Ideally, energy should be abundant, reliable, affordable, environmentally friendly, emissions-free and petroleum-independent. However, these characteristics really represent trade-offs; for example, a highly reliable system costs more, and a balance must be struck between the costs of increasing the reliability of energy supply versus the costs (economic, social, and public health and safety) of not having energy when it is needed. Deciding on this balance is critical for the State. Such a debate depends upon having accurate assessments of the effects of energy technology, policy, and design choices. New technologies in renewable energy, energy use, energy conversion, transmission, and storage offer opportunities to provide clean, reliable, and secure energy for Hawaii at less cost. ***The purpose of the Hawaii Energy Roadmapping Study is to provide Hawaii with the capability of objectively evaluating its energy options and their true costs and environmental consequences***.

The Hawaii Energy Roadmapping Study is an evaluation of the Big Island's future electricity and transportation energy options with respect to local goals and future world conditions from a technology-neutral perspective. The US Department of Energy (DOE), the Hawaii Natural Energy Institute (HNEI), The General Electric Company (GE), and the Hawaiian Electric company (HECO) and its subsidiary the Hawaii Electric Light Company (HELCO) have collectively provided ~$1.5M over a two-year period to fund the first two phases of this study.

Transportation and Electricity Modeling

In Phase 1, the study developed an evaluation process that can effectively assess energy technologies and serve as guide to the development of energy policies. In Phase 2, the process of evaluating various energy infrastructure evolution scenarios will be used to identify programs that have the potential to address Hawaii's need for an affordable, reliable, environmentally acceptable, petroleum-minimizing energy sector.

The Electric System model consists of a *production cost* and *transient performance* model. The *production cost model* is used to help make decisions about which generators should be used to produce electricity in each hour of the day, based on the HELCO system constraints. This model provides information about the variable cost of production, emissions and other operating characteristics. The *transient performance model* is used to understand the impact of transient operation of different generators on system frequency in a seconds timeframe. Both of these models have been validated against 2006 historical conditions and deemed acceptable as a starting point for infrastructure evolution scenarios.

The Transportation Model has been developed and validated against the data provided in the 2005 Hawaii Databook. The transportation fleet, fuel type and vehicle type breakdown were used in conjunction with fuel demand forecasts, fuel price projections, emissions data, and land use information to evaluate economic, environmental, and sustainability metrics. Presentations of the Transportation and Electricity model results are shown in the Appendix. A flow diagram of each model is shown in Figure 1.

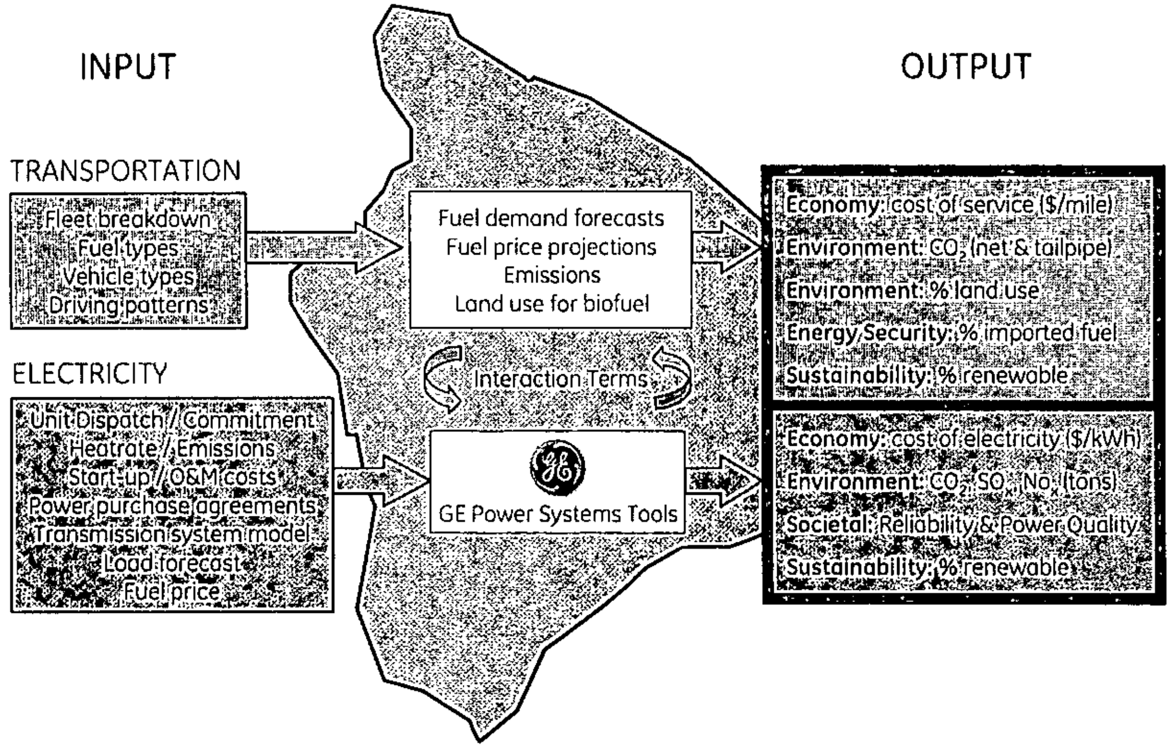


Figure 1: Hawaii Energy Roadmapping Models

It is envisioned that this validated, technology-neutral scenario evaluation tool can be used by policy makers – Local, State and Federal – to give insights and directional estimates of some of the effects of adopting candidate policies or technology strategies. The value of this is to inform discussions on the State's energy roadmap by more accurately determining the effects of energy choices on the supporting infrastructure required and the system performance metrics. Stakeholders identified the relevant metrics during a series of interviews in April and May. A presentation of the results of the stakeholder interviews is provided in the Appendix.

The complexity of energy planning can be demonstrated, as the metrics (cost, environment, reliability, oil independence, public health and safety, economic development, etc.) are often mutually competitive (increasing one metric may require decreasing the others to some extent). While tradeoffs among metrics are to a large extent a policy issue, there are also technical issues. For example, incorporation of as-available energy sources beyond a certain level can be shown to lead to unacceptable levels of system stability and energy availability unless technical mitigating measures are adopted.

Stakeholder Summit

Based on the results of the electric and transportation simulation models and the concerns, preferences and suggestions expressed by the stakeholders during our interviews with them, the project team developed tools to evaluate proposed energy policies and projects in terms meaningful to Hawaii. The Stakeholder Summit was an opportunity to present the results of this initial phase of the project, to explain how we intend to apply what has been learned, and to solicit further input from the diverse interests Hawaii's energy sector must serve. The objectives of the workshop were:

1. To present the capabilities of the energy sector models developed and the metrics to be used to evaluate energy development options.
2. To enable local (county), State and Federal policy makers to explain how they envision using this energy policy/project assessment methodology.
3. To present candidate "scenarios" that we suggest using the models to evaluate in order to exercise the models' capabilities and to provide insight into which strategies would best meet the common objectives of Hawaii's citizens.
4. To try to identify potential technologies or projects that improve Hawaii's energy sector based on a consensus among a diverse group of stakeholders.
5. Finally, to obtain additional broad-based inputs on the above four items and suggestions on how governments, utilities, businesses, consumer and business groups and other organizations could advance our common interests.

An oft-repeated theme during our interviews with Hawaii stakeholders earlier this year was their desire to find ways for utilities, consumers, businesses and environmental groups to cooperate, as partners rather than adversaries, to promote clean and affordable sources of energy in the State. Traditional historical roles, business strategies, and policy positions were not seen as the best ways to address Hawaii's energy issues and, as a result, were seen as also being potentially counter-productive to each stakeholder's achieving its own individual goals. This project hopes to foster constructive dialog and debate on Hawaii's energy choices and, by doing so, to expedite actions, policies or projects that can be chosen by consensus to promote the general good.

Summit Results

The Department of Business, Economic Development & Tourism (DBEDT), Hawaiian Electric Company (HECO), Hawaii Electric Light Company (HELCO), and many other stakeholders assembled on September 27, 2007 at the Marriott Waikoloa, on the Big Island of Hawaii. (A complete list of attendees is provided in the Appendix.) The key stakeholders were given the opportunity to make introductory statements. In the morning session, the transportation and electricity model results were presented, as well as the results of the stakeholder meetings and the scenarios chosen for this second phase of the project. These presentations are provided in the Appendix. In the afternoon session, stakeholders were asked to offer their inputs, advice and suggestions to the project team. Stakeholders offered comments on the overall project strategy and direction for future scenario evaluation. The following paragraphs represent a general summary of the Summit.

HECO/HELCO were generally pleased with the level of detail of the model results and hope the model can be used to inform policymakers of tradeoffs in the electricity sector. The accuracy of the results of the model validation effort exceeded HECO's expectation, and HECO is looking forward to continued cooperation with the project team. HELCO would like to continue cooperating with the project team, especially since using the validated models could predict the efficacy of some of the system design, resource investment, and operating measure changes HELCO is considering in its on-going efforts to improve the electric system on the Big Island. There was general agreement that the high resolution of this tool warrants attention from the federal policymakers.

The State expressed a desire to continue the GE/HNEI/HECO/HELCO partnership and to further develop and apply the tools to help State policymakers identify and quantify tradeoffs. There was general agreement among the stakeholders present that the electric power model can provide answers to some of the questions the State is grappling with concerning various energy technologies, tariff and power purchase regulations, system performance metrics, and other policies. The State recognizes there are legitimate additional costs associated with connecting large amounts of wind generation to the grid (spinning reserve and/or the potential for using other technologies to mitigate intermittency). This model should be used to quantify and communicate that impact to policymakers, understanding the current program is not funded to exhaustively do this. The State is urgently trying to develop solutions to achieve lower energy prices in a world dominated by rising oil prices.

In Phase 2, for each scenario, the analysis will provide quantitative observations about the impacts of specific technology deployments on emissions, variable costs, etc. While the models will not be used for detailed system design and engineering (e.g., each contingency and fault scenario cannot be considered), and the study is not designed to maximize or minimize a specific goal, the models will be used to provide directionally correct information about the impact of technology choices on the economic/environmental metrics. The study cannot be exhaustive and is not intended to replace the HELCO IRP process. The project team must continue to be clear about communicating the capabilities and limitations of the model. (For example, the production cost model is capturing the variable cost of electricity production resulting from different technology deployments. It does not consider the capital costs, lifetime of equipment, rates of return, etc., although those can be separately estimated and incorporated in the assessment.)

The following list represents some of the stakeholder **opinions/comments** from the Summit:

- The model should be used to identify solutions rather than analyze problems.
- The terms of existing power purchase agreements (PPA) have locked the Island into high prices for wind power. Going forward, the terms of new PPAs must change if the island is to achieve a cost-effective renewable energy supply. It is possible that competitive bidding will reduce the prices paid to renewable IPPs in the future.
- Potential wind intermittency mitigation measures, in addition to electric energy storage, include better spillage of wind at the windfarm by the wind developer, or the use of hydro to provide the quick response needed when wind power suddenly declines. Forecasting and improved generator controls may be more cost effective than a strategy incorporating only energy storage.
- If a biofuels industry emerges there can be competition for the commodity between the transportation and electricity sectors on the Big Island.
- The increased energy security (i.e., high use of renewable energy from a very diversified technology base) should incorporate significant amounts of conservation, ocean thermal energy conversion, seawater cooling, and wave power. Such an approach satisfies the energy objectives of the island. Technology immaturity and initial high cost are two reasons high penetrations of ocean-based renewable energy technologies may not be realized by 2018.

The following bullet list represents some of the stakeholder's **suggestions** provided at the Summit. The responses are summarized in italics:

- The project team will need to identify whether the suggested technology deployments in 2018 for each scenario are achievable. *This is a necessary step to ensure the scenarios are grounded in reality.*
- A request was made to include distributed generation in the "enhanced energy management" scenario. *Distributed technologies will represent an important part of this scenario.*
- A request was made to identify and quantify the cost savings of retiring old equipment. *Because this type of analysis must be exhaustive and will require significant input from the utility, the current program is not able to provide this analysis as part of Phase 2. However, this analysis could form the basis of program activities in future portions of the program.*
- A request was made to examine the impact of revising existing/future PPAs. *Due to the parametric nature of the model, sensitivities (such as changes in the PPAs) can be considered for a scenario.*
- It was noted that the model did not consider the impacts of supply interruption on business. *Since the model is technical in nature, the model alone cannot capture these*

impacts, nor can it capture subjective factors, such as aesthetics and cultural impacts of certain technologies.

- HELCO sees great benefit in understanding how much spinning reserve will be needed for additional increments of wind power. *Though this study is not exhaustive, the project team hopes to provide "directionally correct" insight into the effects of spinning reserve on additional increments of wind power.*
- HECO showed an interest in analyzing how demand side management and critical peak pricing can be a surrogate for spinning reserve. *Demand side management will be an important component of the energy management scenario.*
- The State showed an interest in understanding the impact of moderating demand and shifting demand from daytime to nighttime in the energy management scenario. *This type of analysis can be considered in the energy management scenario.*
- Natural gas can be used as a storage option to increase the island's energy security. *The storage of energy commodities, such as natural gas, has not been considered. Additional information about the impact of storage on the price of this and other commodities would be required for this analysis.*
- The stakeholders inquired about the feasibility of adding more wind power to the island. *While this study cannot exhaustively analyze the impact of additional wind power capacity, it can quantify the impact of increasing wind power both with and without mitigating measures.*

Conclusions

The input and time contributed by the various stakeholders was appreciated and adds value to this study. It should be noted that much of the model development was a result of close interaction and time spent with HECO/HELCO staff and management.

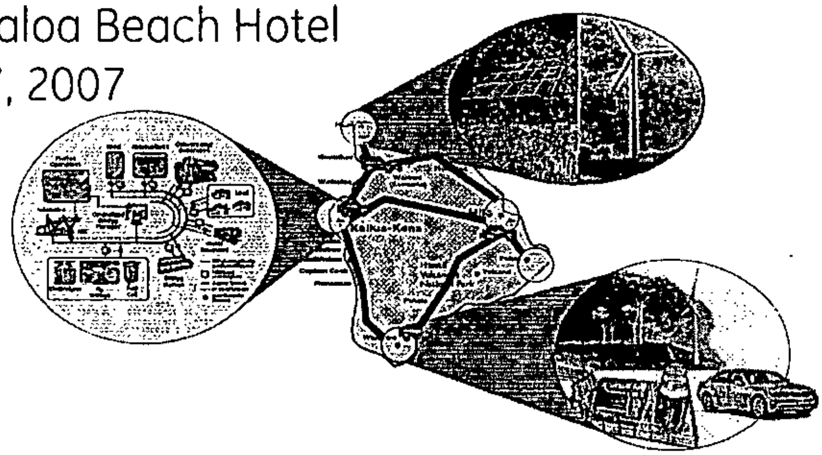
The model results were presented and accepted by the stakeholders in attendance. Based on the consolidation of stakeholder input, scenarios were outlined and presented at the Summit. With general stakeholder acceptance of the scenario themes outlined at the Summit, the project team has commenced more detailed scenario development based on the information and suggestions provided by the stakeholders.

The stakeholders widely accept the objectives of this study and welcome the development of an in-state capability to evaluate policies and to better understand the systems-level impact of various technology decisions. The Strategic Energy Roadmap study intends to create a technically rigorous framework to support this capability.

Appendices

Appendix A – Summit Introduction (Rick Rocheleau)

Big Island Energy Stakeholder Workshop
Marriott Waikaloa Beach Hotel
September 27, 2007

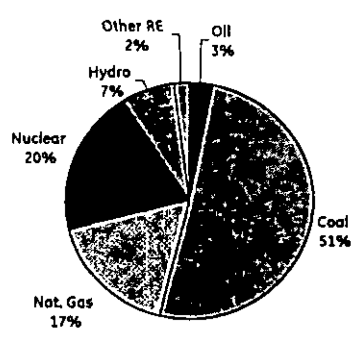


Rick Rocheleau
Director, Hawaii Natural Energy Institute

US DOE | Hawaii Natural Energy Institute | State of Hawaii | GE Global Research GE Energy | Sentech | Hawaii Electric Light Company

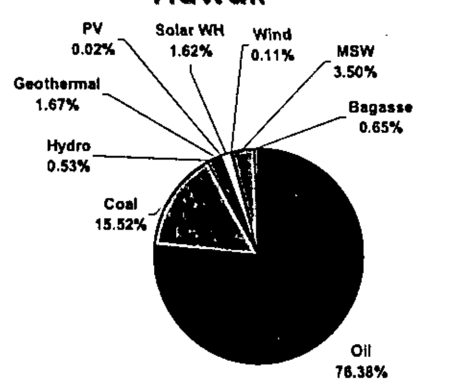
Why are we here?

United States



Source: USEIA

Hawaii



Sources: HECO and KIUC RPS Reports, FERC Form 1 or Annual Reports to PUC, and IPP reports to US EIA

Hawaii needs affordable, reliable, environmentally acceptable energy

Develop roadmap to address Hawaii's future energy needs

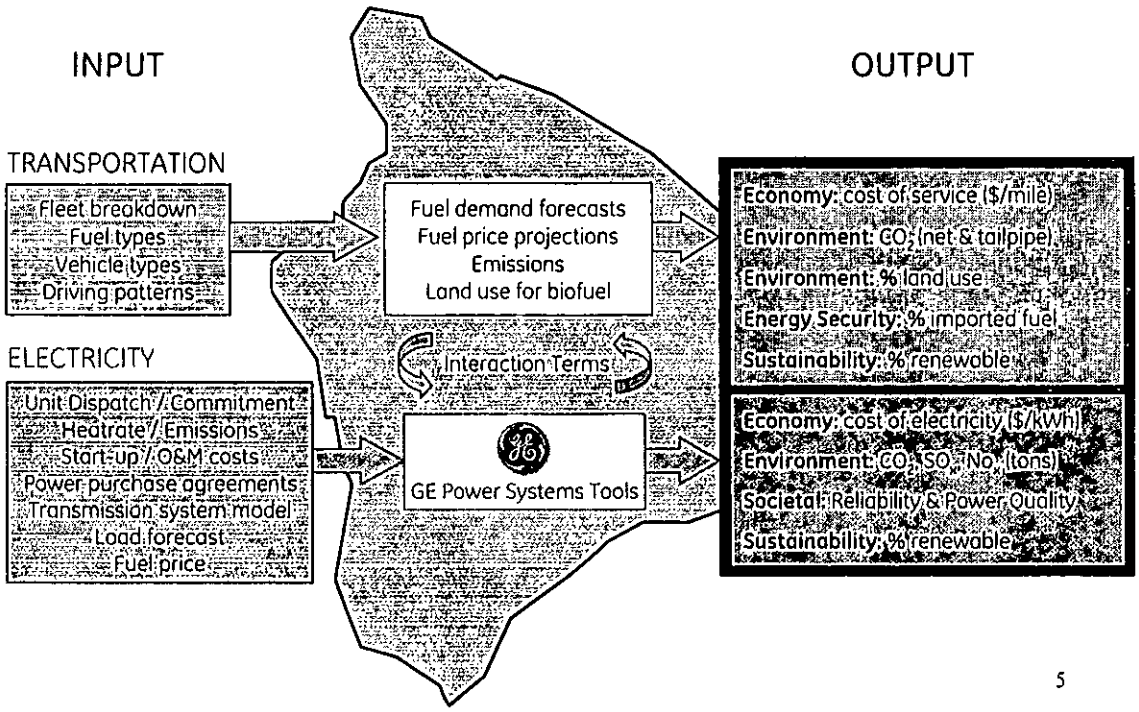
Hawaii Energy Roadmap

- What is it? An technical and economic evaluation of the Big Island's future electricity & transportation energy options with respect to local goals and potential future world conditions
- Objectives:
  - **Phase 1** - Develop an evaluation process and tools that can effectively assess economic and technological implications of various energy scenarios
  - **Phase 2** - Use this process to identify and evaluate programs to transform Big Island energy infrastructure to meet stakeholders target objectives (e.g. affordable, reliable, environmentally acceptable, etc.)
  - Future – Input to decision maker .... implementation

Hawaii Energy Resource Technologies for Energy Security

- Part of a partnership between Hawaii and New Mexico (UH and NMT)
- Objectives include to develop, demonstrate, and deploy technologies to **facilitate greater penetration of Hawaii's renewable resources** into its energy systems;
- Three tasks with Big Island Focus:
  - ***Hawaii Road-mapping – Assessment of Electrical and Transportation Infrastructure and Microgrid Applications***
  - **Research, Development and Testing of Critical DER and Microgrid Technologies at Hawaii Gateway Energy Center.**
  - **Development of Public Policy and Outreach to Accelerate DER/Microgrid Acceptance – support for Hawaii Energy Policy Forum**
- Partners include GE, HELCO, HECO, Sentech, DOE, and DBEDT.

Electricity / Transportation Models



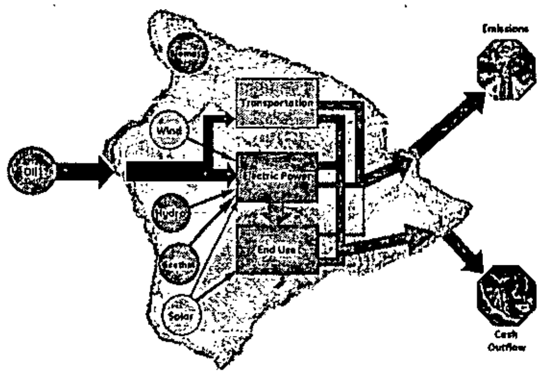
Process

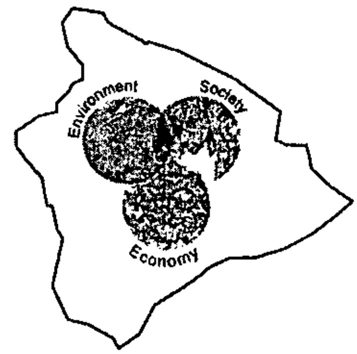
- Develop team and define common goals - HNEI, GEGRC, GE Energy Systems, HELCO, HECO, DOE, DBEDT
- Develop tools (models) that describe current transportation and energy systems of the Big Island. **Validate** models to insure acceptance by all members of the partnership
- Survey stakeholders, define needs and desires of community, and define metrics
- Identify potential future scenarios based on stakeholder input and preliminary model analysis
- *Re-engage stakeholders to insure scenarios address concerns of the stakeholders. Modify as appropriate*
- *Develop selected scenarios to identify potential (technical and economic) to help address Hawaii energy needs considering stakeholder objectives including national needs.*

Appendix B - Scenarios & Stakeholder Interview Summary (Terry Surles, Larry Markel, Devon Manz)

Hawaii Energy Roadmap

Stakeholder Input & Scenario Formulation





Terry Surles Hawaii Natural Energy Institute
Larry Markel Sentech, Inc.
Devon Manz GE Global Research

US DOE · Hawaii Natural Energy Institute · State of Hawaii · GE Global Research GE Energy · Sentech · Hawaii Electric Light Company

Stakeholder Summit

Objectives of today's meeting

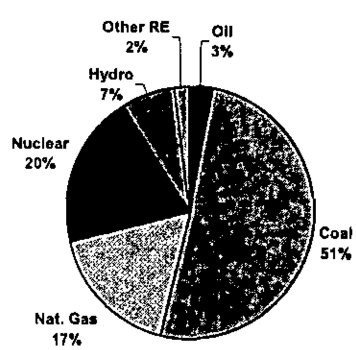
1. To **update** the assembled stakeholders:
   a. Capabilities of the **models** developed and the **metrics** used to evaluate options.
   b. To **present candidate scenarios** – developed from Stakeholder interviews
   c. **Discuss** how scenario strategies meet common program and stakeholder objectives
2. To enable public and private policy makers to explain how they envision using this assessment methodology
3. To obtain additional **input, advice, and suggestions** from Stakeholders on future paths for energy activities

End Result of Today's Meeting: Obtain **input, advice, and suggestions** on energy activities

1. Comments on overall project strategy and direction
   Are we on the right track, based on our earlier discussions with you?
2. Comments and direction on future scenario evaluation
   What are your thoughts on the most/least appropriate scenarios?
3. Comments and advice on additional areas to be considered
   Are we missing anything that you feel is important for the future?

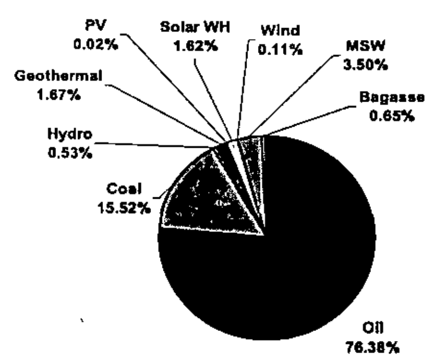
Electricity Generation by Source 2003 – Why we need to reduce petroleum dependency

United States



Source: USEIA

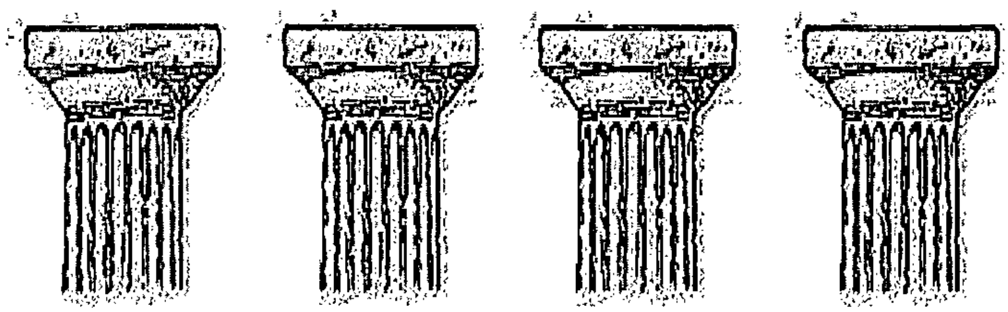
Hawaii



Sources: HECO and KIUC RPS Reports, FERC Form 1 or Annual Reports to PUC, and IPP reports to US EIA

Public-Private Partnerships Are Critical For Addressing Overarching Issues Facing the Nation's Energy Systems

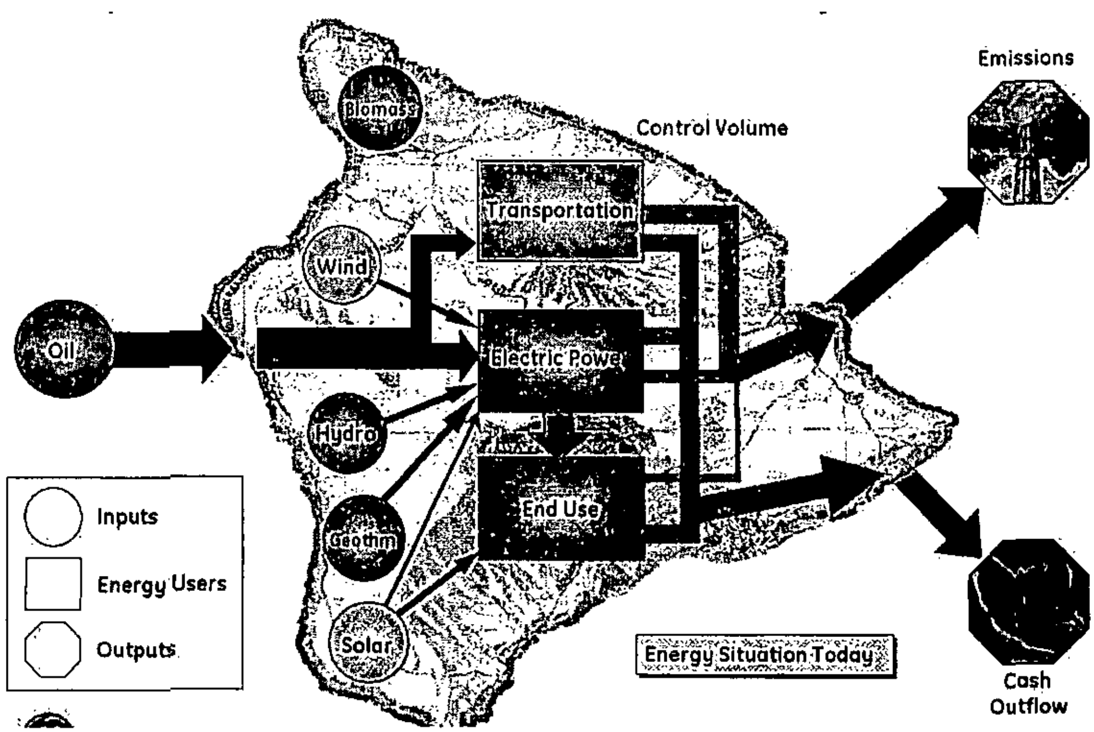
Energy System of the Future



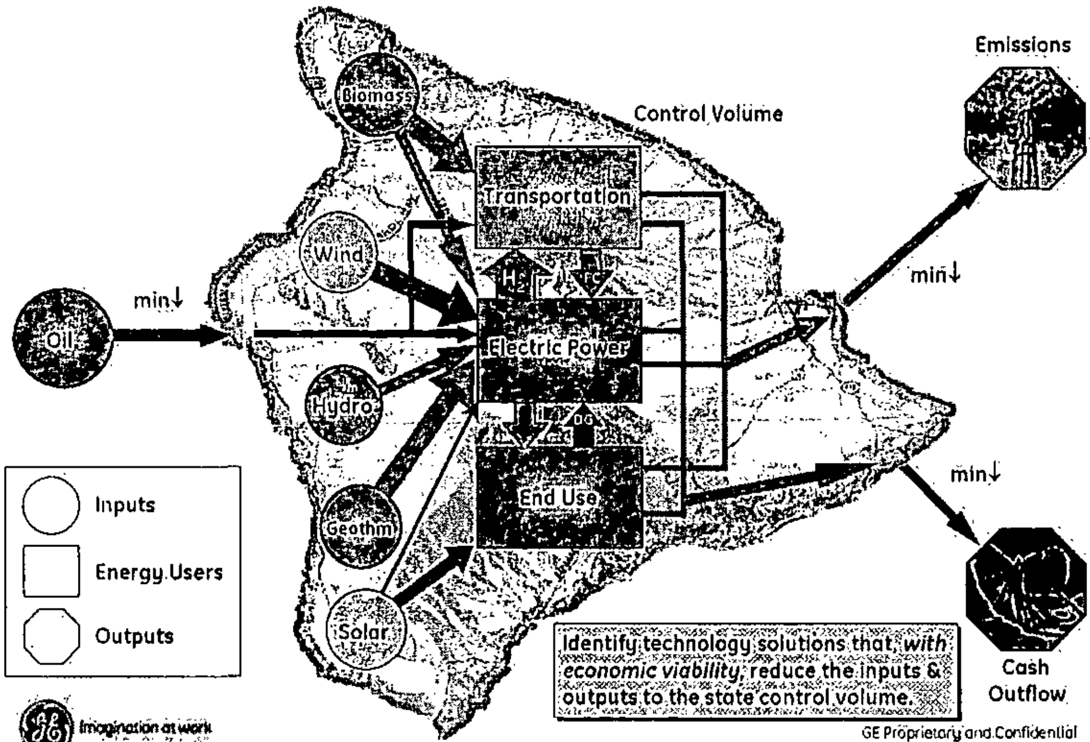
Grid Modernization | Global Climate Change | Energy Security - Transportation/Electricity | Environment Quality

None Of These Issues Can Be Resolved Without Partnerships - The Right Kind of Partnership Fosters Innovation for Hawaii

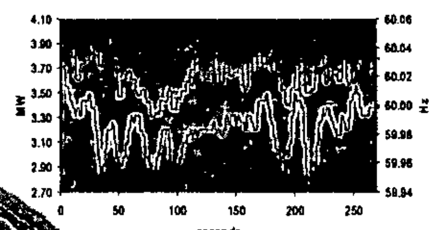
DOE and State Objectives - Sustainability



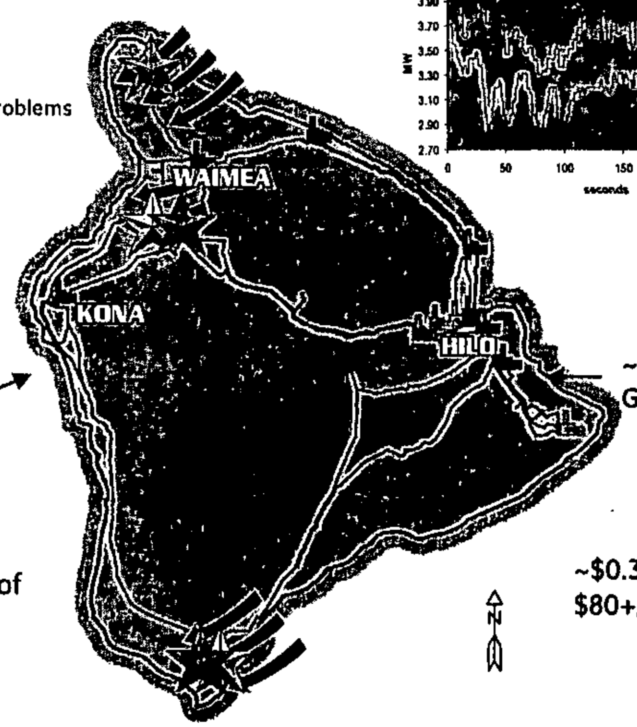
DOE and State Objectives - Sustainability



Big Island Challenges



Growing Use of Wind Causes Problems with Grid Frequency



Transmission Congestion ~60% of Island Load

~75% of Island Generation

High Cost/Security of Energy – 90% Dependence on oil

~$0.30/KWh, $80+/bbl oil

Phase 1
Modeling, Validating, Calibrating - Completed

Electricity and transportation sector models describe current Big Island energy system

Models have been calibrated and validated against historical data to the high degree of accuracy required to meet project objectives

Result:

Analytical tools and baseline for technical and economic assessment of infrastructure futures

Can be used to establish effective parameters for future growth of the Big Island

Tools not intended for day-to-day decision making

Development of Better Planning Tools is a Goal Shared by All

Meet DOE mission needs
- Lessons and analytical tools for Mainland grids
- Incorporation of new technologies into grid

Address utility system planning needs
- Understand the implication of more renewable energy
- Mechanism for evaluating new technologies to address system impacts

Address state initiatives for customer benefits, public goods
- understand implications of RPS and other initiatives for reducing petroleum use
- Big Island as a potential showcase for renewable energy and the installation of innovative technologies

Phase 2

Energy Roadmapping - Just starting

Evaluate technical and economic impact of alternative energy infrastructure scenarios for the Big Island, starting from the base case

Scenarios developed based on stakeholder interviews

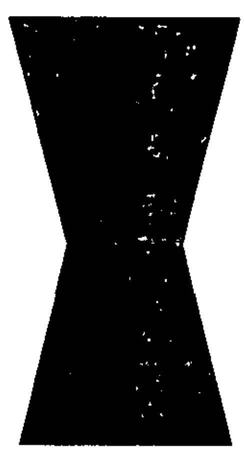
Continue collaboration with HECO/HELCO, state, and county to ensure model evolution is grounded in operational reality

Work with various stakeholders (i.e., government, end-users, IPPs, environmental and economic NGOs) to ensure concerns and opportunities are addressed

A Conceptual View of the Big Island Project

We started with an expansive view of the future

We were need to get



constrained by the the models right

Now, we can think expansively again

What does this study offer?

- A calibrated and validated technical, economic **and** environmental analysis of **both** the electricity and transportation infrastructures on the Big Island.
- A methodology and tool for State policymakers and utility leaders to analyze the impacts and tradeoffs of technologies and policies.
- An in-state capability to perform further energy analyses.

The ability to quantify the environmental, economic and technical tradeoffs of energy technologies and policies in the State.

Stakeholder Engagement

1. Stakeholder Interviews

- What are your key energy-related **metrics**?
- What are your **energy goals** for 2020?
- Is 2020 an appropriate **target** for the study?
- What do you see as **key global influences**?
- What do you see as key **energy technologies**?
- What **policies** should Hawaii implement?
- What other **energy issues** concern you?

Stakeholder Interviews → Consolidation of Stakeholder Input → Identification of Themes → Scenario Development

April | May | July | September

County of Hawaii Energy Office
Bob Arrigoni
Economic Development Alliance of Hawaii
Paula Helfrich
Enterprise Honolulu
Mike Fitzgerald and John Strom
Fairmont Orchid
Ed Andrews
Hamakua Energy Partners
Joe Clarkson
Hawai'i County Council
Pete Hoffmann
Hawai'i Island Economic Development Board
Mark McGuffie
Hawaiian Electric Company, Ltd.
Karl Stahlkopf
Hawai'i Electric Light Company, Inc.
Hal Kamigaki, Chengwu Chen, Art Russell, Lisa Dangelmaier
Hawi Renewable Development
Jim Nestman, Raymond Kanehaikua
Hilton Waikaloa Village
Rudy Habelt (Director of Property Operations)
Kahala Center
Betsy Cleary-Cole (Deputy Director)
Life of the Land
Henry Curtis (Executive Director)
Office of Hawaiian Affairs
Mark Glick Yuko Chiba
Powerlight
Riley Saito
State of Hawaii, Department of Business, Economic Development & Tourism
John Tantlinger, Steve Alber, Priscilla Thompson
State of Hawaii, Public Service Commission, Division of Consumer Advocacy
Catherine Awakuni
Tesoro Hawaii Corporation
Carlos De Almeida
University of Hawaii at Manoa
Makena Coffman

3. Identification of Themes

Stakeholder Interviews → Consolidation of Stakeholder Input → Identification of Themes → Scenario Development

State Policy Goals	Ancillary Power Generation	Utility Partnerships
Energy & Economic Security, Climate Change	Key Energy Metrics	Energy Technologies

Theme 1: State Energy Policy Goals

1. Energy efficiency,
2. Maximizing the use of indigenous resources,
3. Enhancing energy security,
4. Minimizing greenhouse gas emissions, and
5. Reducing the cost of energy.

The majority of stakeholders agree with these overarching goals. However, there is concern that some policy decisions may result in unanticipated adverse effects.

Theme 2: Wind Energy Issues and Opportunities

Wind is good...

But the 21st MW of wind is better than the 71st MW
- *Diminishing returns*

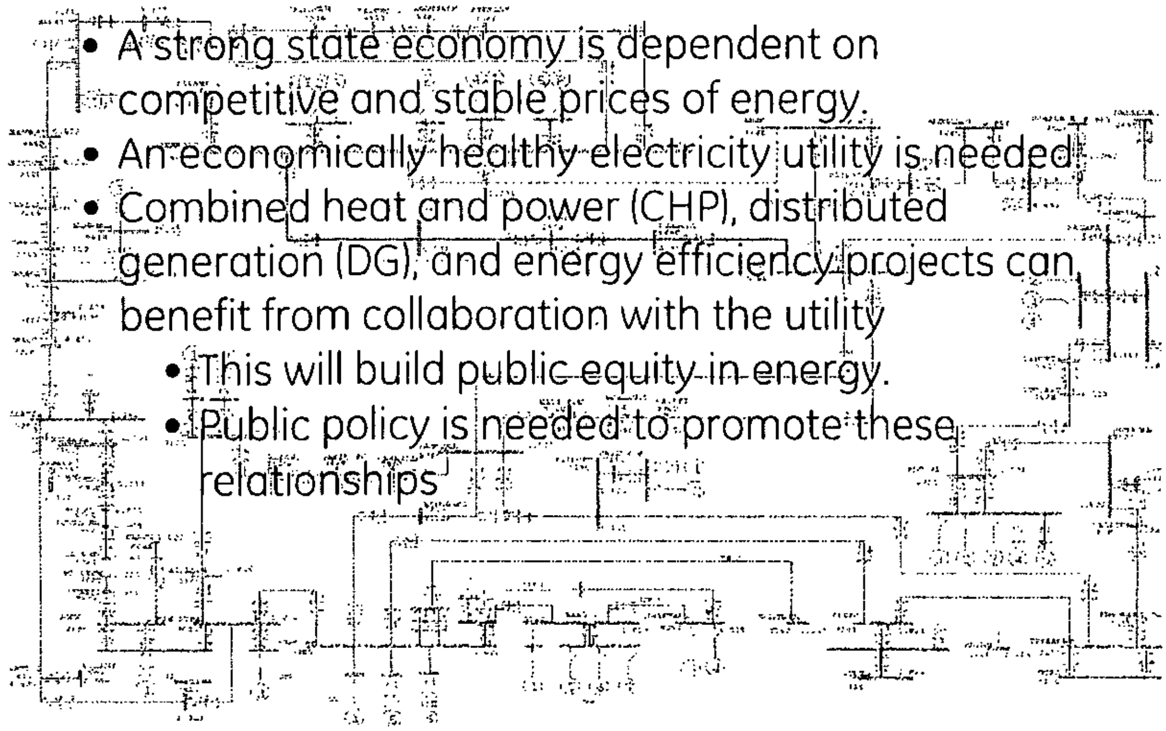
To maintain system stability, we may need to burn more oil
- *Regulating reserves*

At night, we may have to "dump" wind
- *Difficult to finance new wind projects*

There are technologies (and policies) that can help HELCO and Hawaii utilize more wind
- *Energy storage, AGC tuning, economic incentives*

- Some stakeholders believe Hawaii could reduce the cost of electricity by increasing the penetration of wind power.
- General lack of awareness of the ancillary services needed.
- Understanding the "true cost of wind" can provide the State with data for policies for this and other technologies

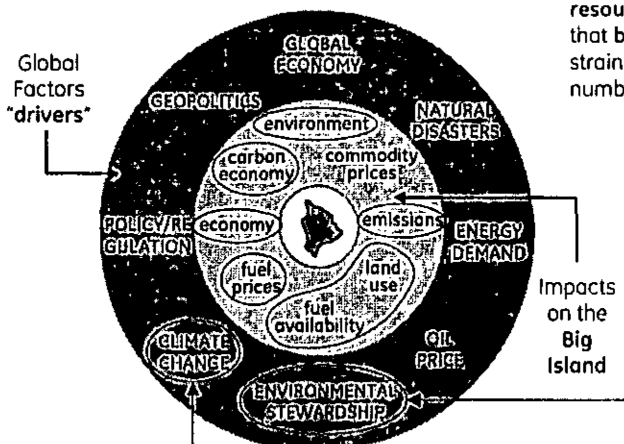
Theme 3: Utility Partnerships



- A strong state economy is dependent on competitive and stable prices of energy.
- An economically healthy electricity utility is needed.
- Combined heat and power (CHP), distributed generation (DG), and energy efficiency projects can benefit from collaboration with the utility
  - This will build public equity in energy.
  - Public policy is needed to promote these relationships

Theme 4: Biofuels, Energy & Economic Security, & Climate Change

ENERGY SECURITY is centered around **indigenous production of energy resources.** Stakeholders are concerned that **biofuels may displace food crops,** strain the water supply, and create a number of byproducts with no direct use.



BIOFUELS - If fuel crops on the Big Island are more expensive to produce than importing the same fuels from abroad, will **Hawaii import biofuels** or the commodity to produce biofuels.

CLIMATE CHANGE MITIGATION is a central policy goal for the State. **Nearly unanimous agreement** was received from the stakeholders

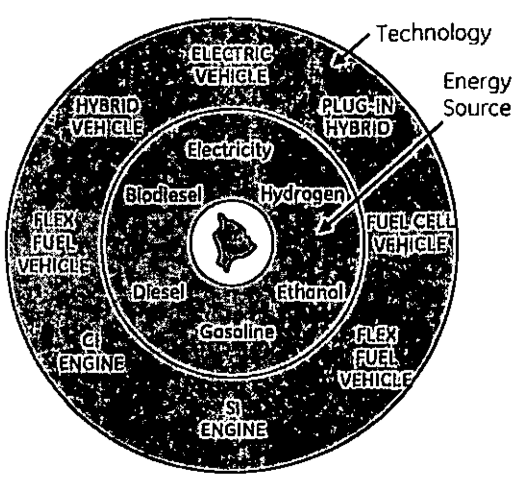
Theme 5: Key Energy Metrics

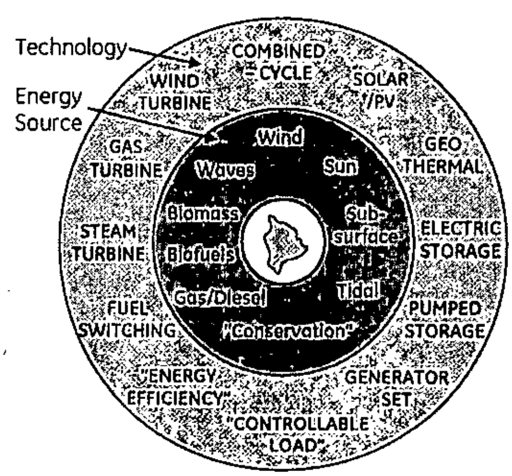
CLASSIFICATION		METRIC
Economic	*Cost*	$/kWh (Electricity), $/gal (Transportation)
Sustainability	*Penetration of Renewables*	% renewable
Energy Security	*Petroleum Use*	% petroleum
Social	*Many Factors*	Land, water, cultural values, aesthetics
Environmental	*Emissions*	tons/year (CO_2, NOx, SOx)

Theme 6: Energy Technologies

Most commonly mentioned energy technologies:

1. Wind Power & Energy Storage Technologies
2. Biofuels (palm oil, micro-algae, eucalyptus) for Transportation
3. Plug-in Hybrid Electric Vehicles,
4. Distributed Solar Power
5. Gasification (coal, waste, biomass) for Power Generation
6. Enhanced Grid Communications/Controls/Monitoring





4. Scenario Development

Stakeholder Interviews → Consolidation of Stakeholder Input → Identification of Themes → **Scenario Development**

1. Scenarios were chosen based on the six themes discussed by the stakeholders.
   - Two technology-focused scenarios and two goal-oriented scenarios.

2. A baseline model will be developed for 2018 with the proposed technology deployments for each scenario taking place in that year.

INCREASING ENERGY SECURITY

Based on a specific technology deployment that is focused on using indigenous resources, especially renewable resources (wind, solar, geothermal, biofuel).

Key Metric

% reduction in petroleum use

HIGHER WIND PENETRATION

Given the trends in Hawaii for increased wind farm development, a renewable energy strategy consisting primarily of increased wind utilization will be considered.

Key Metric
% increase in wind power

REDUCING ELECTRICITY COSTS

Based on a change in customer energy use habits and/or a specific technology deployment that is focused on achieving the lowest energy cost, given assumptions about the future policy landscape and price of fuel.

Key Metric
Cost of electricity (cents per kWh)

ENHANCED ENERGY MANAGEMENT

Using new and/or innovative approaches, such as demand-side management, customer-sited energy storage, energy efficient technologies and plug-in hybrid electric vehicles to contribute to regulating reserve requirements.

Key Metric

Cost of electricity (cents per kWh)

Scenario Checklist

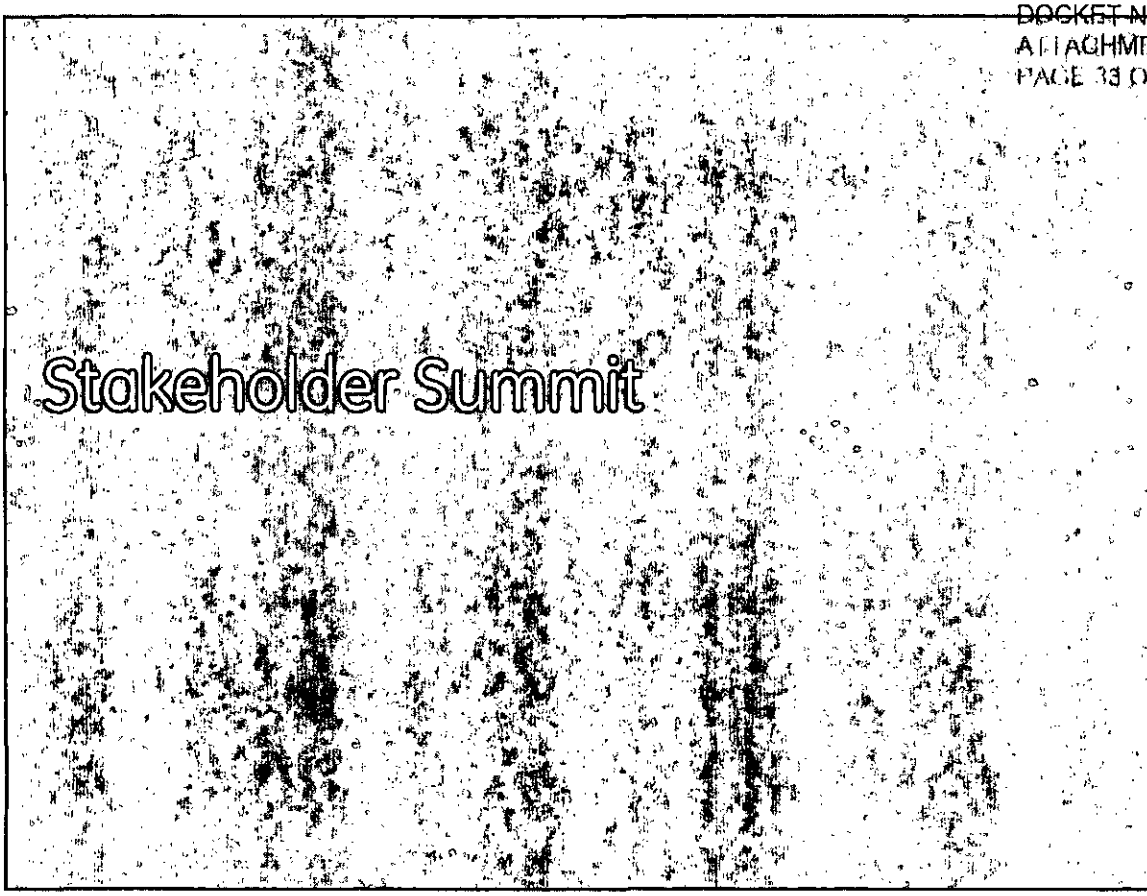
SCENARIO	FOCUS	KEY METRIC	THEMES					
			1	2	3	4	5	6
Increasing Energy Security	Goal-oriented	% imported	X			X	X	X
Reducing Cost of Electricity	Goal-oriented	$/kWh	X			X	X	X
Higher Wind Penetration	Technology	% renewable		X		X	X	X
Enhanced Energy Management	Technology	$/kWh			X	X	X	X

For each Scenario we must consider future variables...

Scenario Elements	Impact
Energy Storage Technologies	Maintains power system stability by providing support for intermittent renewables, while minimizing the curtailment of renewables.
Oil Price	Fluctuations in the oil price will impact the cost of electricity, transportation, citizen behavior
Carbon Policy	The economics of lower carbon-emitting technologies will be enhanced relative to fossil-fuel counterparts.
Renewable Portfolio Standards	Alternative target dates and percentages could affect the cost of energy in a non-linear fashion.
Power Purchase Agreements	Changes to this policy will affect the price HELCO and ratepayers pay future independent power producers.
Energy Cost Adjustment Charge	Changes to this policy will affect customer and utility finances and promote technologies that hedge against rising oil prices.

Summary of Past Events and Next Steps

1. The opinions of stakeholders were solicited in April and May 2007.
2. Consolidation of stakeholder input revealed six common themes.
3. These themes were used to construct technology and goal-oriented scenarios for the year 2018.
4. Details of these general scenarios will be constructed by observing the impact on cost, emissions, etc. of incremental changes to a base case.
5. Each scenario will be constructed using technology deployments and making assumptions about future policy landscapes and global conditions.



Stakeholder Summit
Objectives of today's meeting

1. To **update** the assembled stakeholders:
    a. Capabilities of the **models** developed and the **metrics** used to evaluate options.
    b. To **present candidate scenarios** – developed from Stakeholder interviews
    c. **Discuss** how scenario strategies meet common program and stakeholder objectives
2. To enable public and private policy makers to explain how they envision using this assessment methodology
3. To obtain additional **input, advice, and suggestions** from Stakeholders on future paths for energy activities

Accomplishments to Date

- A validated set of models that account for the complexities of Hawaii's energy sector
- A method to evaluate key technical issues and policy questions
- An evaluation of metrics (sometime competing) important to the values of Hawaii's citizens
- A local capability to do these analyses and assessments in the State

What we're hoping will result

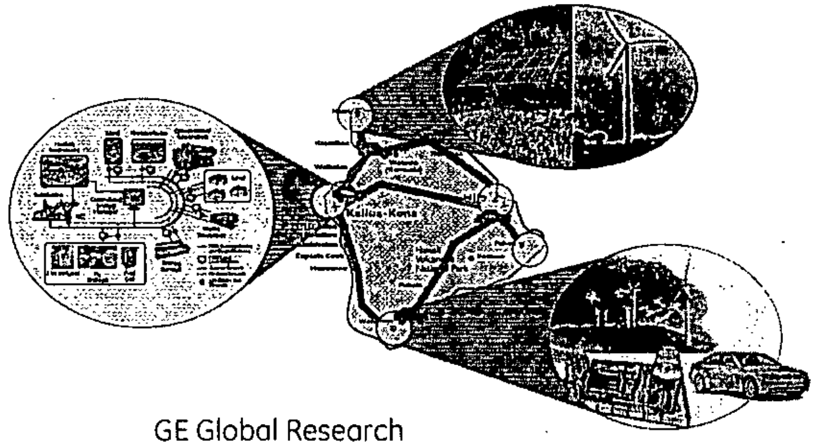
1. Establish the analytical capability in Hawaii to support more informed planning and policy processes
2. Focus the dialog in Hawaii on tradeoffs among feasible choices, not abstract technology advocacy
3. Quantify the value of alternate technologies, and determine where they can best be utilized
4. Support, with accurate and technology-neutral analysis, on-going Hawaii planning and policy activities
5. Identify some individual energy technology choices or projects that should be expedited
6. Facilitate development of partnerships and new business relationships among stakeholders to achieve common objectives

What We Hope to Obtain from the Stakeholder Audience Today

1. Comments on overall project strategy and direction
   Are we on the right track, based on our earlier discussions with you?
2. Comments and direction on future scenario evaluation
   What are your thoughts on the most/least appropriate scenarios?
3. Comments and advice on additional areas to be considered
   Are we missing anything that you feel is important for the future?

Appendix C – Results of the Transportation Model (Steve Sanborn)

Hawaii Strategic Energy Roadmap
Transportation System

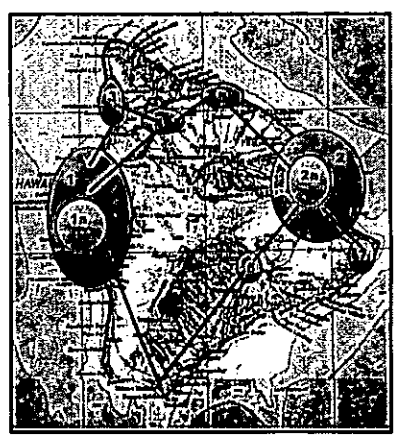


Stephen Sanborn GE Global Research
Devon Manz GE Global Research
Ralph McGill Sentech, Inc.

US DOE Hawaii Natural Energy Institute State of Hawaii GE Global Research GE Energy Sentech

---

Approach



Assessment Envelope
- o Big Island of Hawaii

Infrastructure Segments
- o Sources (importation & on-island sources, production/conversion into transportation energy carriers, bulk storage)
- o Distribution (receiving terminal(s), pipelines, tanker truck fleet(s) trucking, intermediate storage)
- o Dispensing Capacity (by geographic region)

Consumption Segments
- o Granular Vehicle Classes
  (e.g., passenger cars, light duty trucks, heavy duty trucks, tractor trailers, buses, etc.)
- o Subdivide into existing major fleets as relevant
  (e.g., # vehicles by vehicle-class & fuel type for Personal, Retail & Delivery, Entertainment-Tourism, Public Transportation, Airport Ground Support, Off-Road & Construction, Marine, Military, etc.)
- o Functionalize for scenario analysis
  - o % growth of current petroleum-fueled fleets
  - o Addition of selected alternative fuel fleets (i.e., add usage of ethanol, biodiesel, H2 & electricity)

imagination at work

Scope

Capability to Quantify Transportation Energy & Fuels Scenarios

- Transportation Fuel Consumption
  - Bottoms-up estimate rooted in baseline 2004 vehicle fleet data for Big Island
  - Segmentation & Granularity by:
    - Fuel type (gasoline, diesel, propane, electricity, ethanol, biodiesel, hydrogen)
    - Energy Flow (actual & capacity), by energy carrier type, for each geographic region
    - Vehicle Fleets with a reasonable degree of vehicle class & fuel type & miles traveled. *(NOTE: aircraft and large commercial vessels not included in Phase 1)*
- Interactions with Electric Power Model:
  - Electricity demand *(future use of electricity as "fuel" or for H2 production)*
  - Biofuel consumption *(future use of biofuels by both Transportation & Electricity)*
- Broad-based growth (& growth constraints) anticipated by stakeholders
- Global Fuel Market future price projections as an upper bound
- Quantified measures that roll-up into Metrics

Validation: "Current Situation Scenario should replicate the current situation in Hawaii.

Assessment: "Current Snapshot " - Best Estimate of year 2005 transportation consumption & quantitative values for metrics

"Future Snapshot" - Single point projection to the year 2020.

- Sensitivity Analysis

imagination at work

Metrics

Energy Security **–** The diversity of Fuel Types & sources used to meet demand. (e.g., % petroleum, % renewable, % biofuel, % imported, % produced either on-island or at least within Hawaiian Islands)

Economics - Cost-Of-Service (COS) **–** Based on market price estimates for fuel types used in scenario, and then applied to the elements of the vehicle fleets (e.g., \$/gal, \$/vehicle/mile, \$/vehicle/year)

Environmental Impacts **–** Tailpipe emissions with vehicle fleet & fuel type granularity, agricultural land requirements by crop/fuel type.

Societal Impacts **-** These are user interpretations of underlying scenario results with focus on: land use and the above metrics. Considerations relate to: Land use & impact on local customs; Acceptance by on-island residents &, tourists; Citizen Health & Safety.

Transportation Specific Sensitivities

$\delta\, COS_{ervice}$ / δ %ethanol (or other biofuels)

δ Tailpipe Emissions/ δ %ethanol use (or other biofuels)

δ Land Required/ δ %ethanol (or other biofuels)

imagination at work

Model

INPUT → **Processing** → **Output**

INPUT

Parametric Data:
- Vehicle Fleets with class, fuel type & miles/year
- Alternative Fuel production parameters
- Fuel Spot Price benchmark parameters

Pro-Forma User Input:
- *WHAT-IF scenario changes*
  - *% change in # of vehicles by type*
  - *% change in miles per year by type*
  - *Scenario Year for price projection*
  - *% change in MPG by type*
- *Alternative Fuel Fleet(s)*
  - *Define Fleet size and fuel*
  - *Define miles/year/vehicle & MPG*
  - *Select alternative fuel feedstock(s) for CAPEX & biomass agriculture land use*

Processing

Estimate fuel demand:
- whole island
- each conventional fleet
- each alternative fleet

Estimate fuel prices:
- Estimate Hawaii retail price of:
  - gasoline & diesel based on spot and market prices.
  - biofuels based on projections.

Estimate emissions:
- Tailpipe CO2 & criterion emissions
- Well-To-Tank CO2 emissions

Estimate Land-use:
- Estimate feedstock specific biomass acreage needed

Output

Energy Security
- % of fuel is petroleum
- % of fuel is biofuels
- % of fuel is green fuels
- % of fuel is electricity or elec-based

Economic
- $$/gallon for fuel types
- $$/mile for vehicle type
- $/year for vehicle type
- CAPEX estimates:
  - Alternative Fuel production

Environmental/Societal
- Well-to Wheel and Tailpipe Emissions
  (CO2, CO, NOx, SOx, VOC, PM10)
- % Agricultural Land area required for local biomass production

imagination at work

Validation

	Hawaii Databook 2004	Infrastructure Model (A)	Infrastructure Model (B)	Hawaii Databook 2005	Infrastructure Model (C)	Infrastructure Model (D)
Gas Demand (Mgal)	*not reported*	62.17	63.9	74.148	68.1	69.93
Diesel On-Road Demand (Mgal) *	*not reported*	10.34	15.76	11.535	13.76	16.52
Diesel Off-Road Demand (Mgal)	*not reported*	9.25	9.25	9.54	9.54	9.25
Total Fuel (Mgal) *	85.40	81.76	88.91	89.00	91.40	95.7
		-4.3%	4.1%		2.7%	7.5%
Miles/year/vehicle	9,729	9,730	10k - 1[illegible]	10,043	10,032	10k - 15k
Total Vehicle Miles (Mmiles) *	1,516.6	1,613.3	1,701.4	1,651.2	1,784.8	1835.9
Total Vehicles *	168,229	168,231	168,231	178,524	180,338	180,338

*excludes tractor trailers

Within 10%

Model (A): Vehicle Data set for 2004 Databook

Model (B): Vehicle Data set for 2004 with adjusted miles/vehicle/year

Model (C): Vehicle Data set for 2005 Databook

Model (D): Vehicle Data set for 2005 with adjusted miles/vehicle/year

imagination at work

Forward-Looking Snapshots

Scenario "Tuning Knobs"

- # of vehicles in each sub-fleet
- Miles/year/vehicle for each sub-fleet
- MPG improvement for vehicles in each sub-fleet
- Addition/substitution of alternative fuel sub-fleets
- Ethanol blending ratio & feedstock(s)
- Biodiesel blending ratio & feedstock
- Calendar Year for fuel pricing

Vehicle Fleet Growth & Changes

- Pop. and GCP growth as surrogate indicators
  - 37% pop. growth by 2020 → personal vehicle fleet
  - 44% increase in Hawaii GCP by 2020 → commercial fleet
- Penetration of E-FFVs and B-FFVs
  - **Target:** 20% renewable fuels by 2020
  - **Estimate:** 14% FFVs by 2020 (Biofuels Summit)

Hawai'i County

	2005	2020	%
Population	163K	203K	25%
Population (+tourists)	166K	227K	37%
Gross County Product (B$ 2000)	4.3	6.2	44%
Personal Income ($/yr/per)	23K	30K	30%

Source: Population and Economic Projections for the State of Hawaii to 2030, DBEDT

imagination at work

Sensitivities in 2020

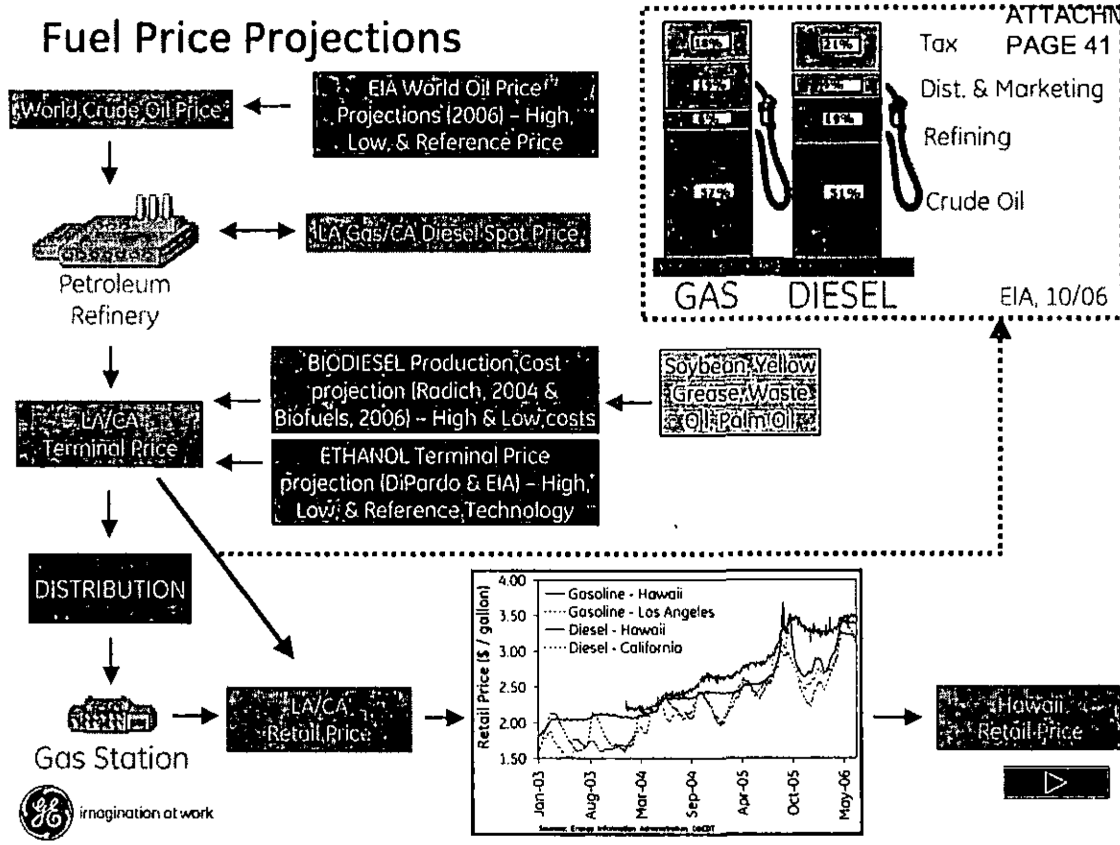
In 2020, the situation might look like this:

- *+37% On-Island population growth*
- *+44% County Gross Annual Product growth*
- *E-FFVs and B-FFVs readily available*

SCENARIOS	Spark Ignition	Compression Ignition	2005	2020
Baseline	Gas	Diesel	X	X
100% E10	E10	Diesel	X	X
100% B5	Gas	B5	X	X
100% Blended fuels	E10	B5	X	X
20% E85	Gas/E85	Diesel		X
20% B80	Gas	Diesel/B80		X
20% E85 & 100% B5	Gas/E85	B5		X
20% B80 & 100% E10	E10	Diesel/B80		X

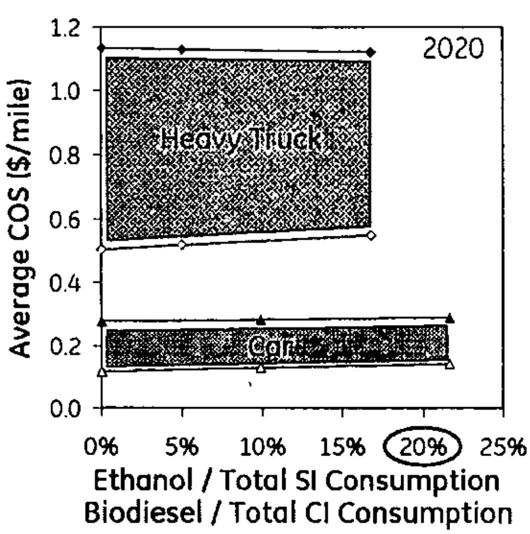
imagination at work

Fuel Price Projections



imagination at work

Results - Monetary Cost of Energy Security

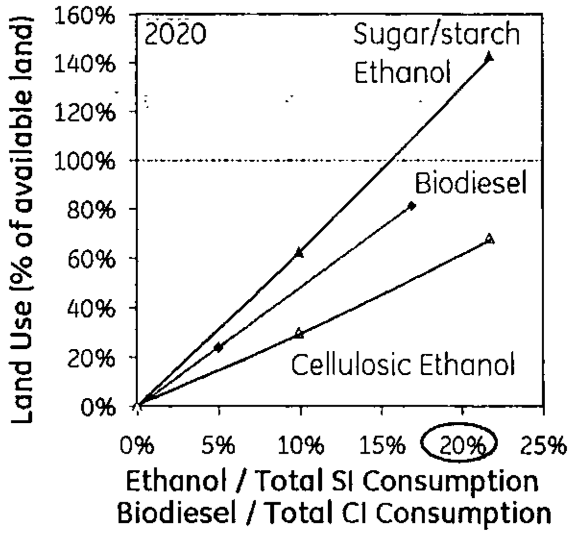


Penetration of Biofuels

- The average cost-of-service was determined for two vehicle fleets for the year 2020 scenarios.
- The high and low COS are calculated from the high and low fuel price projections.
- The method in which the 20% Alternative fuels standard is achieved has an effect (i.e. E85 vs E10).
- The monetary cost of increasing energy security through the use of biofuels will largely not be borne by the consumer.

imagination at work

Results – Environment/Societal Cost of Energy Security



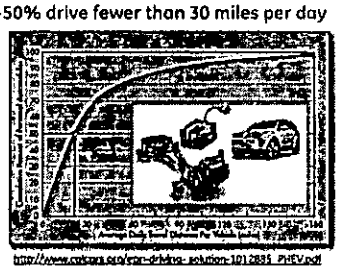
Penetration of Biofuels

- The acres of available land were obtained form the RMI Biofuels Summit.
  - 23,200 acres was used here
  - 27,000 per Stillwater, or ultimate land estimates such as 1,200,000 acres could be used as appropriate
- The 20% Alternative fuels standard can be achieved in various ways.
- It will be challenging to reach the 20% standard with on-island produced biofuels alone.

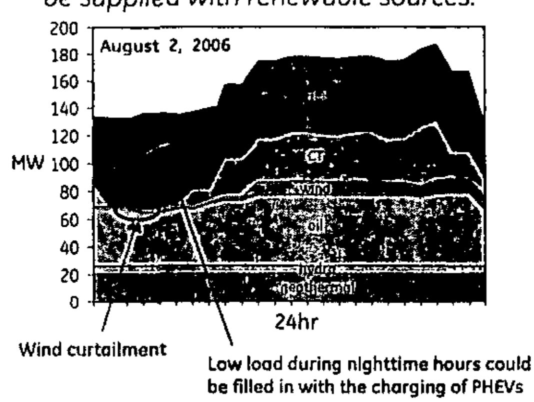
Phase 2 Scenario Analysis

There is potential for some transportation energy to be shifted to the power system.

~50% drive fewer than 30 miles per day



At night EV/PHEV charging could be supplied with renewable sources.



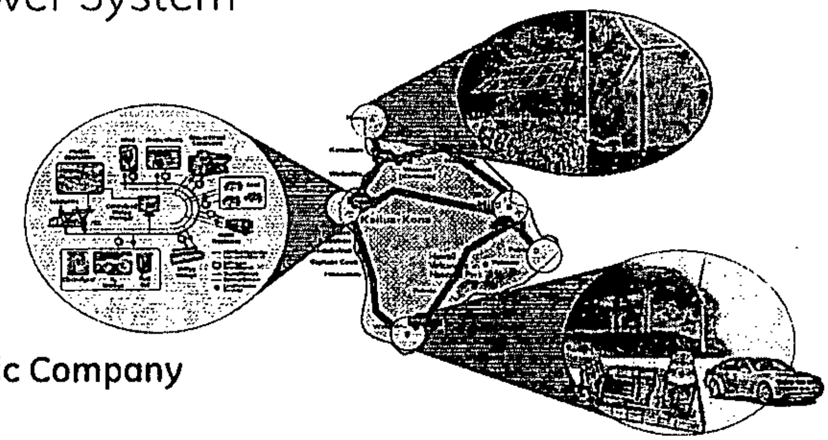
Future Work

The potential role of PHEVs in providing generation reserve for the power system, thereby reducing the cost of electricity and potential overall emissions, will be evaluated.

Appendix D – Results of the Electricity Model (Nick Miller)

Hawaii Strategic Energy Roadmap

Electric Power System



General Electric Company
Nick Miller
Gene Hinkle
Sebastian Achilles
Juan de Bedout
Devon Manz

US DOE | Hawaii Natural Energy Institute | State of Hawaii | GE Global Research GE Energy | Sentech | Hawaii Electric Light Company

Project Approach - 50,000ft view

In Phase 1...

- The project team developed and validated a model of the HELCO system.
- The model was used to determine how incremental changes (in wind, solar, geothermal, etc) impact the cost of electricity, emissions, imported petroleum, etc.

In Phase 2...

- Four scenarios, comprised of various technology deployments, will be evaluated by the project team.
  - The stakeholders have and will provide substantial input into the scenario formulation process.
- The model will be used to evaluate the key metrics (i.e., cost of electricity, % renewable, % imported) for each scenario

What does this study offer?

- A calibrated and validated technical, economic **and** environmental analysis of the electricity infrastructure on the Big Island.
- A methodology and tool for State policymakers to help analyze the impacts and tradeoffs of technologies and policies.
- An in-state capability to perform further energy analyses.

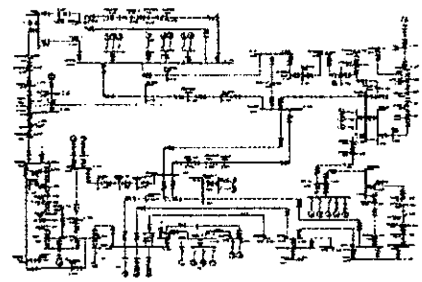
The ability to quantify the environmental, economic and technical tradeoffs of energy technologies and policies in the State.

What are the limitations of this study?

- The production cost modeling tool considers only the variable cost (fuel, O&M and start-up of each unit). In order to fully analyze the tradeoffs, additional information is needed, such as the capital cost of a technology deployment.
- The electricity model is not an exhaustive study, nor is it a substitute for utility planning (HELCO IRP).
- The model is a quantitative tool and does not output qualitative issues, such as siting, aesthetics, cultural values, etc.

Electrical System Modeling

The model is comprised of two specific simulation packages:

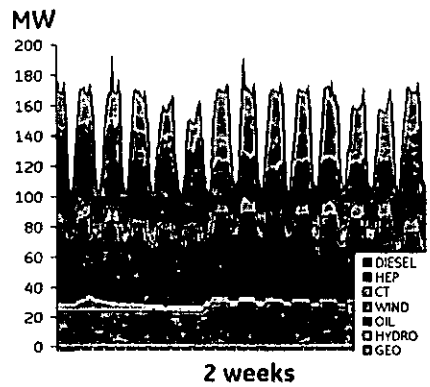


1. Dynamic Simulation (GE PSLF™)

- Transient Stability Simulation
- Long-Term Dynamic Simulation
  - Second-by-second load, wind variability driving full dynamic simulation of the HELCO grid for several thousand seconds (~1 hour)

2. Production Simulation (GE MAPS™)

- Hour-by-hour simulation of grid operations



Constructing Phase 2 Scenarios

Impact of adding:

X MW of wind/solar/geothermal, or
X MW of spinning reserve, or
X MW of storage, or
X MW of load....

These incremental changes to the baseline model will be used to identify the impact of various technologies on achieving specific goals (i.e., How does the addition of 1MW of geothermal energy change cost of electricity?)

ON

Economy: Cost of electricity ($/kWh)

Environment: CO_2, SO_x, NO_x, (tons)

Energy Security: % imported petroleum

Sustainability: % renewable

WILL BE USED TO CONSTUCT FOUR SCENARIOS

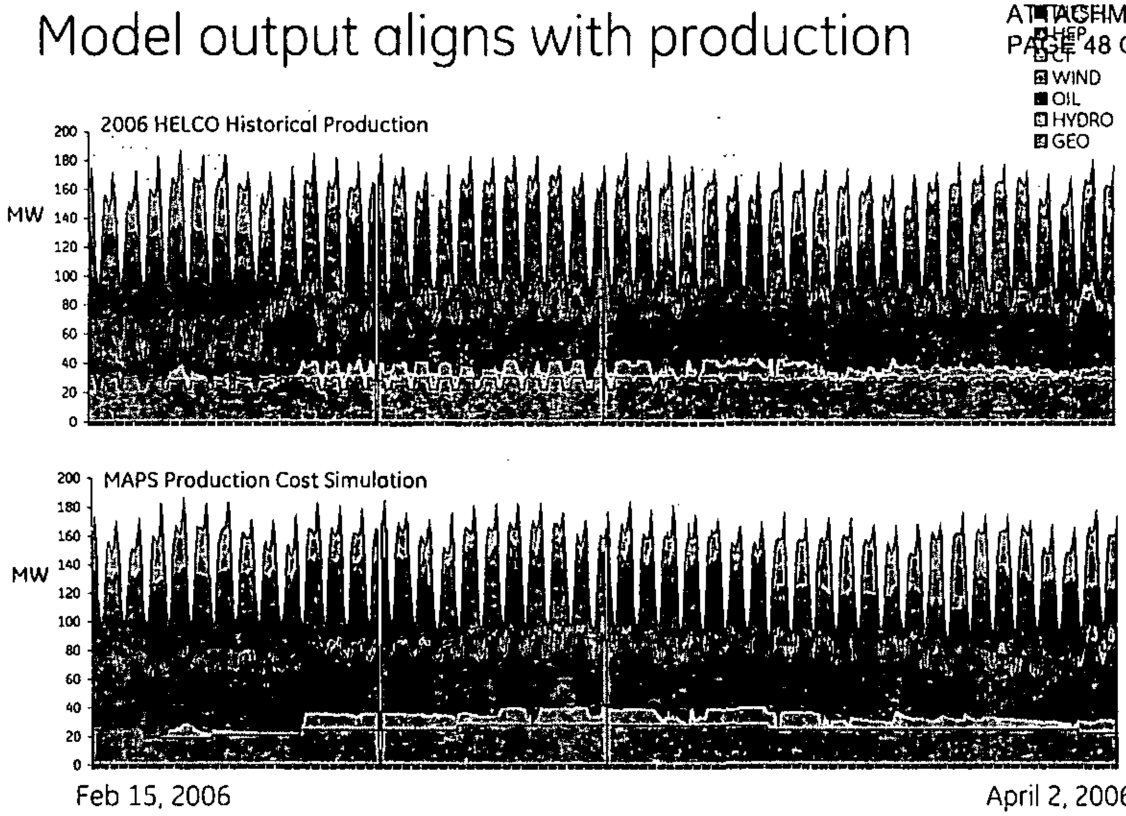
Production Cost Modeling
GE MAPS™

imagination at work

What is production cost modeling?

- Throughout the year HELCO has to make decisions about which generators should be used to produce electricity in each hour of the day.
- This decision depends on **many** constraints, including the cost of each generator, the capabilities of the transmission system, and rules about when each generator can be operated.
- **GE MAPS™,** the production cost tool used in this study, was used to simulate the HELCO production for 2006.
- Production cost modeling allows HELCO to determine the cost of electricity production, emissions, etc ne

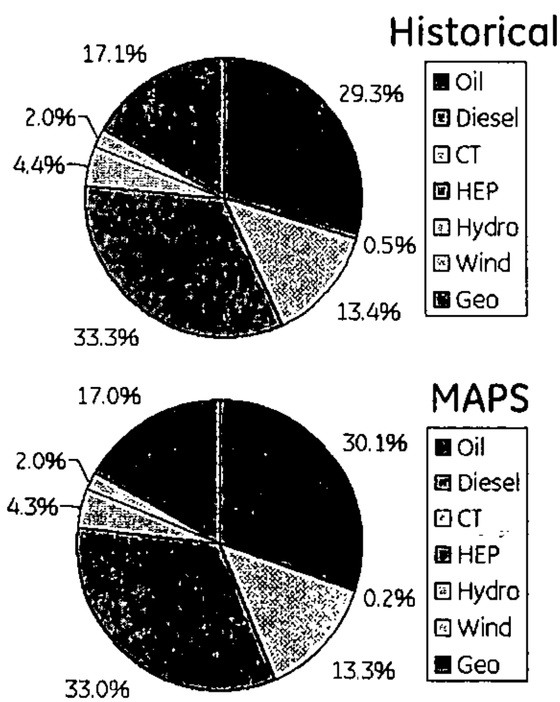
Model output aligns with production



9

The model validates annual production

Annual Production (GWh by Fuel Type)



	GWh (2006)	
	Historical	MAPS
Oil	364	376
Diesel	6	3
CT	166	167
HEP	414	412
Hydro	54	54
Wind	25	25
Geo	212	212
Total	1241	1250

Less than 1% difference between actual annual GWh (by type) in 2006 and the results of the MAPS model.

Dynamic Simulation GE PSLF™

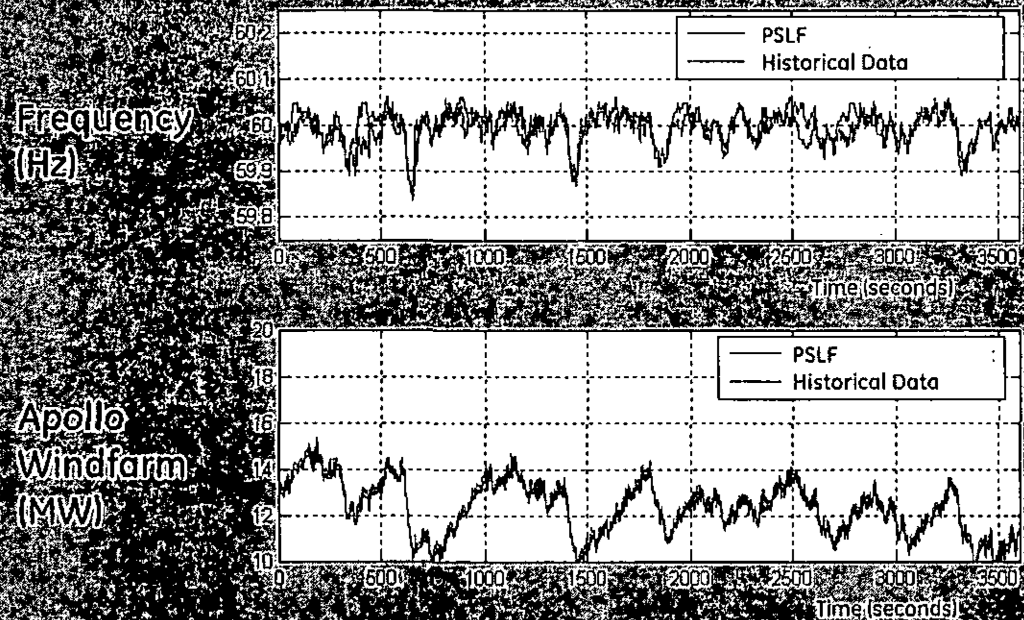
imagination at work

What is dynamic modeling?

- Dynamic (or transient stability) modeling is used to simulate the system behavior (such as frequency) during transient operation.
- Dynamic modeling can be used to understand the impact of transient operation of different generators on system frequency in a seconds timeframe.
- Dynamic modeling is needed to ensure that system frequency remains relatively stable during critical operating practices
    - eg. A gust of wind during the night causes a large windfarm to quickly produce additional electricity. If another generator is unable to reduce its electricity production as quickly as the windfarm picked up, the system frequency will deviate from 60Hz.
- **GE PSLF™** was used to simulate HELCO operation

Model results align with historical data

Example: Significant Wind Fluctuation (04/03/07)



What are the types of analyses we can perform with this tool?

imagination at work

What if 1MW of wind power is added to Apollo wind farm?

		Fuel Use	Emissions (tons)		
	GWh	MMBtu	NOx	SOx	CO_2
Combined Cycle	-2.1	-15545	0	-2	-1352
Combustion Turbine	-1.3	-13905	-1	-2	-1245
Diesel	0.0	-341	0	0	-29
Puna Geothermal	0.0	0	0	0	0
Small Hydro	0.0	0	0	0	0
Steam Oil	-0.6	-7582	-1	-1	-726
Wind	4.1	0	0	0	0
Solar	0.0	0	0	0	0
Grand Total	0.1	-37374	-2	-6	-3352

- With no other changes to the system, an increase in wind power offsets fossil fuel generation and reduces emissions
- But, HELCO must maintain their system frequency at 60Hz.
- Sudden changes in wind power output will affect the frequency, therefore increasing wind power requires some additional considerations.

Is there more to this story?

Cost Adders

Wind power reduces the island's carbon footprint, and reduces the amount of imported petroleum, but...

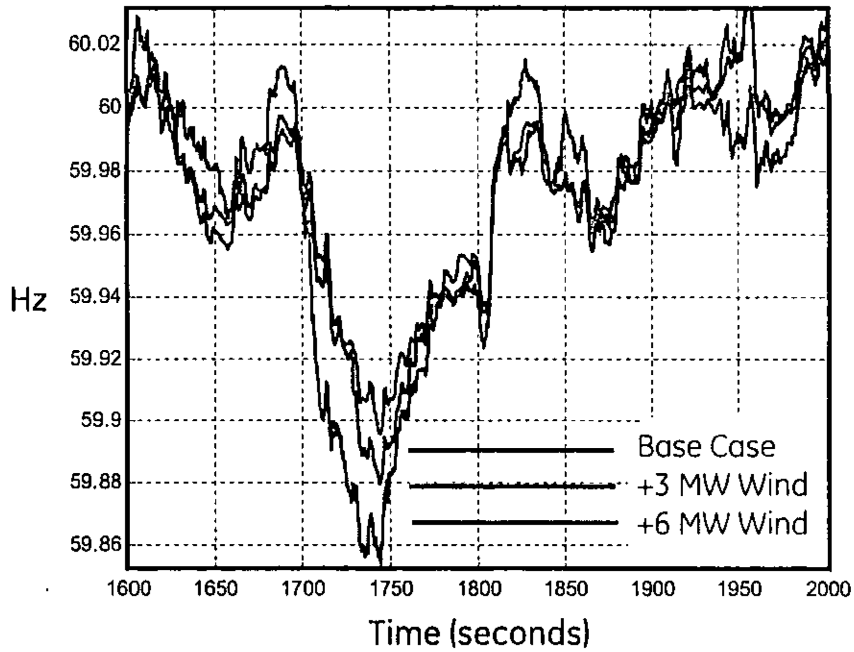
↑ 1) **More spinning reserve will be needed** - More oil must be burned so some generation is ready to quickly meet changes in the system load or wind farm output, and/or

↑ 2) **New technologies** can be used to mitigate the intermittency of wind power.

? 3) **Price paid to wind producers** matters. If HELCO pays a wind producer more than it costs them to produce electricity from fossil fuel generation, more wind power will cost the island more.

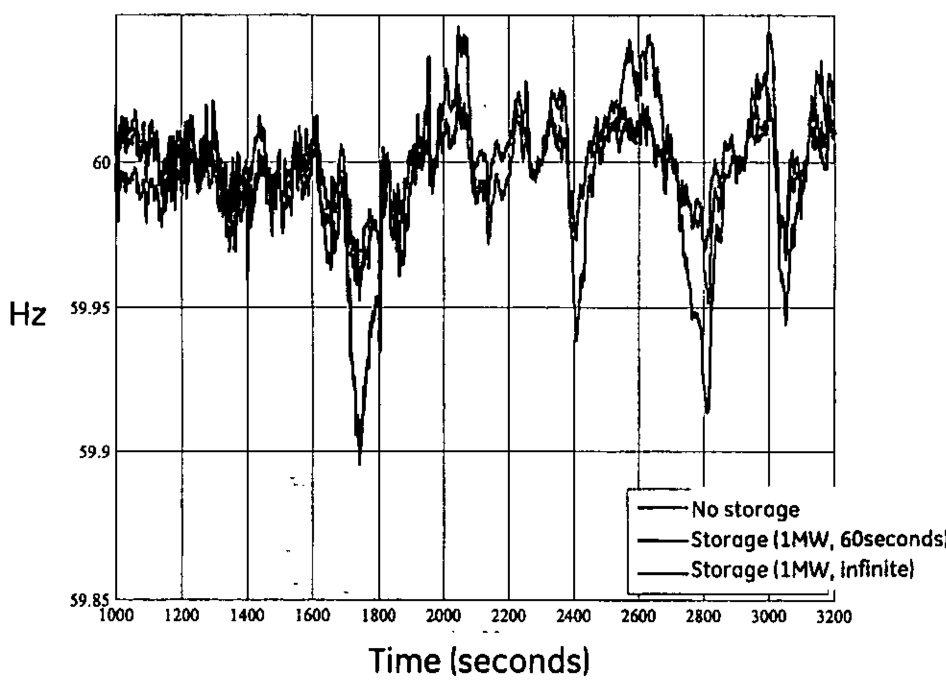
Example: What if HELCO had More Wind?

Significant Wind Fluctuation on May 23rd 2007



Example: Does Energy Storage Help?

Significant Wind Fluctuation on May 23rd 2007



Conclusions

1. GE has developed an electricity model that has validated an entire year of production based on historical data from 2006.
2. The model is capable of quantifying the environmental, economic and technical tradeoffs of incremental changes in power generation and other technologies, however this study **is not** exhaustive and **is not** a substitute for IRP.
3. The discussion of incremental changes of various technology deployments from the baseline provides direction for scenario development.
4. We will be opening the floor to the stakeholders, for discussion, this afternoon.

Appendix E – Summit Participants List

Stakeholder Summit
Waikoloa Bach Marriott, September 27, 2007

PARTICIPANTS LIST
(Revised 10/12/07)

Eduardo Andrews
Director of Engineering
The Fairmont Orchid, Hawaii
1 N. Kaniku Drive
Kohala Coast, HI 96743
Phone: (808) 887-7548
Fax: (808) 885-1125
Email: ed.andrews@fairmont.com

Bob Arrigoni
Energy Coordinator, County of Hawaii
Hawaii County Research & Development
Lanihau Professional Center
25-5591 Palani Road, Suite2001
Kailua-Kona, HI 96740
Phone: (808) 327-3664
Fax: (808) 327-3667
Email: rarrigoni@co.hawaii.hi.us

Eliot Assimakopoulos
Business Development Manager
GE Global Research
One Research Circle, KW D278B
Niskayuna, NY 12309
Phone: (518) 387-7639
Fax: (518) 387-5449
Email: assimako@research.ge.com

Paul Berry
Pacific Network TV
P.O. Box 61296
Honolulu, HI 96829-1296
Phone: (808) 247-4090
Fax:
Email: docberry@aol.com

William Bonnet
Vice President, Government & Community Affairs
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, HI 96840-0001
Phone: (808) 543-5660
Fax: (808) 543-7202
Email: bill.bonnet@heco.com

Michael Bradley
Asst Superintendent, System Operations
Hawaii Electric Light Company, Inc.
Phone: (808) 969-0325
Fax: (808) 969-0416
Email: michael.bradley@helcohi.com

Joe Clarkson
Operations & Maintenance Superintendent
Hamakua Energy Partners
P.O. Box 40
Honokaa, HI 96727
Phone: (808) 775-1711
Fax: (808) 775-1801
Email: jclarkson@hamakuaenergy.com

Betsy Cleary-Cole
Deputy Director
The Kohala Center
P.O. Box 437462
Kamuela, HI 96743
Phone: (808) 887-6411
Fax: (808) 885-6707
Email: cole@kohalacenter.org

Henry Curtis
Executive Director
Life of the Land
76 N. King Street, Suite 203
Honolulu, HI 96817
Phone: (808) 533-3454
Email: henry.lifeoftheland@gmail.com

Lisa Dangelmaier
Operations Superintendent
Hawaii Electric Light Company, Inc.
P.O. Box 1027
Hilo, HI 96721-1027
Phone: (808) 969-0427
Fax: (808) 969-0416
Email: lisa.dangelmaier@helcohi.com

Juan de Bedout
Manager, Electric Power & Propulsion Systems
General Electric Company
Global Research Center
One Research Circle, K1, Rm 3C31
Schenectady, NY 12309
Phone: (518) 387-5676
Fax: (518) 387-7592
Email: debedout@crd.ge.com

Mitch Ewan
H2 Systems Program Manager
Hawaii Natural Energy Institute
Sch. of Ocean & Earth Science & Technology
University of Hawaii at Manoa
1680 East West Road, POST 109
Honolulu, HI 96822
Phone: (808) 956-2337
Fax: (808) 956-2336
Email: ewan@hawaii.edu

David Figueira
Senior Account Manager
General Electric Company
Water & Process Technologies
91-207 Kolili Place
Kapolei, HI 96707
Phone: (808) 282-1345
Fax: (808) 674-9174
Email: david.figueira@ge.com

Mark Glick
Director of Economic Development
Office of Hawaiian Affairs
711 Kapiolani Bloulevard, Suite 500
Honolulu, HI 96813
Phone: (808) 594-1911
Fax: (808) 594-0255
Email: markg@oha.org

Rudy Habelt
Director of Property Operations
Hilton Waikoloa Village
425 Waikoloa Beach Drive
Waikoloa, HI 96738-5710
Phone: (808) 886-2310
Fax: (808) 886-2907
Email: rudy_habelt@hilton.com

Gene Hinkle
Senior Engineer
General Electric Company
Energy Consulting
1 River Road, 2-639
Schenectady. NY 12345
Phone: (518) 335-5447
Fax: (518) 385-3165
Email: gene.hinkle@ps.ge.com

Pete Hoffmann
Council Chairman for District 9
Kona Council Office
75-5706 Hanama Place, Suite 109
Kailua-Kona, HI 96740
Hawaii County Council
Phone: (808) 887-2069
Fax: (808) 961-8912
Email: phoffmann@co.hawaii.hi.us

Maurice Kaya
Chief Technology Officer
Strategic Industries Division
Energy Planning & Policy Branch
Department of Business, Economic Development & Tourism
P.O. Box 2359
Honolulu, HI 96804
Phone: (808) 587-3812
Fax: (808) 586-2536
Email: mkaya@dbedt.hawaii.gov

Warren Lee
President
Hawaii Electric Light Company, Inc.
P.O. Box 1027
Hilo, HI 96721-1027
Phone: (808) 969-0124
Fax: (808) 969-0100
Email: warren.lee@helcohi.com

Devon Manz
Energy Systems Engineer
GE Global Research
Electronics & Energy Conversion
Electric Power & Propulsion Systems Lab
One Research Circle, K1-3C17
Niskayuna, NY 12309
Phone: (518) 387-7684
Fax: (518) 387-7592
Email: manz@ge.com

Larry Markel
Vice President
Sentech, Inc.
700 S. Illinois Avenue, Suite A-210
Oak Ridge, TN 37830
Phone: (865) 483-0359, ext. 104
Fax: (865) 483-0439
Email: Lmarkel@sentech.org

Ralph McGill
Fuels Analyst
Sentech, Inc.
702 S. Illinois Avenue, Suite B-204
Phone: (865) 483-0359, ext. 102
Fax: (865) 483-0439
Email: RMcGill@sentech.org

Nicholas Miller
Principal
GE Energy
1 River Road, 2-605
Schenectady. NY 12345
Phone: (518) 385-9865
Fax: (518) 385-5703
Email: nicholas.miller@ge.com

Bruce Norman
General Manager
Controls Product Line
GE Energy
1 River Road
Building 37, Room 569
Schenectady, NY 12345
Phone: (518) 387-7072
Fax: (518) 387-7571
Email: norman@ge.com

William Parks
Principal Engineer & Senior Advisor
Strategic Industries Division
Dept. of Business, Economic Development & Tourism
Energy Planning & Policy Branch
P.O. Box 2359
Honolulu, HI 96804
Phone: (808) 587-2663
Fax: (808) 586-2536
Email: wparks@dbedt.hawaii.gov

Richard Rocheleau
Director
Hawaii Natural Energy Institute
Sch. of Ocean & Earth Science & Technology
University of Hawaii at Manoa
1680 East West Road, POST 109
Honolulu, HI 96822
Phone: (808) 956-8890
Fax: (808) 956-2336
Email: rochelea@hawaii.edu

Riley Saito
Senior Manager, Hawaii Projects
SunPower Corporation
Pacific Regional Office
P.O. Box 38-4299
Waikoloa, HI 96738
Phone: (808) 895-0646
Fax: (808) 325-6256
Email: rsaito@sunpowercorp.com or rsaito@powerlight.com

Stephen Sanborn
Diagnostics Engineer
Energy & Propulsion Technologies
General Electric Company
Global Research
One Research Circle
Building ES, Room 604
Niskayuna, NY 12309
Phone: (518) 387-4155
Fax: (518) 387-7989
Email: sanborn@research.ge.com

Charles Senning
Project Manager Distributed Generation
The Gas Company
P.O. Box 3000
Honolulu, HI 96842-3000
Phone: (808) 594-5517
Fax: (808) 594-5528
Email: csenning@hawaiigas.com

Karl Stahlkopf
Sr. Vice President
Energy Solutions & Chief Technology Officer
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, HI 96840-0001
Phone: (808) 543-7655
Fax: (808) 543-7657
Email: kstahlkopf@heco.com

John Strom
Project Director for Alternative Energy
Enterprise Honolulu
737 Bishop Street
Suite 2040, Mauka Tower
Honolulu, HI 96813
Phone: (808) 521-3611 ext17
Fax: (808) 536-2281
Email: jstrom@enterprisehonolulu.com

Terry Surles
Researcher
Hawaii Natural Energy Institute
Sch. of Ocean & Earth Science & Technology
University of Hawaii at Manoa
1680 East West Road, POST 109
Honolulu, HI 96822
Phone: (808) 956-5196
Fax: (808) 956-2336
Email: surles@hawaii.edu

Maria Tome
Alternate Energy Engineer
Strategic Industries Division
Energy Planning & Policy Branch
Department of Business, Economic Development & Tourism
P.O. Box 2359
Honolulu, HI 96804
Phone: (808) 587-3809
Fax: (808) 587-3820
Email: mtome@dbedt.hawaii.gov

Norman Verbanic
Manager, Production
Hawaii Electric Light Company, Ltd.
P.O. Box 1027
Hilo, HI 96721-1027
Phone: (808) 969-0421
Fax: (808) 969-0425
Email: norman.verbanic@helcohi.com

ZE-IR-111
Please produce all results obtained from the Simulink model for the utility electric system on the island of Lanai, and all input assumptions used to obtain such results.

HECO Companies Response:

The HECO Companies are not conducting any modeling work with Simulink. Efforts on Lanai are being conducted by Sandia National Laboratories.

ZE-IR-112
Please produce all results obtained from the General Electric Multi-Area Production Simulation (MAPS) models for the utility electric systems on the islands of Oahu, Hawaii and Maui, and all input assumptions used to obtain such results.

HECO Companies Response:

MAPS is a GE licensed program which is used for production simulation modeling. Depending upon the particular analysis being performed, the HECO Companies utilize PMONTH or Strategist for generation planning and do not have licenses to run GE models. GE models were only utilized by GE and not by the utilities for conducting scenario-based analysis as part of specific projects (See Companies' response to HREA-IR-1 and HREA-IR-2 and ZE-IR-110). The tailored assumptions for these study projects were not designed to analyze the impacts of FIT-eligible resources and thus the models constructed are not applicable for FIT modeling.

<u>ZE-IR-113</u>
Please produce all studies and/or reports relating to the General Electric PSLF models for the utility electric systems on the islands of Oahu, Hawaii and Maui.

<u>HECO Companies Response:</u>

Please see the response to ZE-IR-110.

ZE-IR-114
Please produce all studies and/or reports relating to the Simulink model for the utility electric system on the island of Lanai.

HECO Companies Response:

The HECO Companies are not conducting any modeling work with Simulink. Efforts on Lanai are being conducted by Sandia National Laboratories.

ZE-IR-115
Please produce all studies and/or reports relating to the General Electric MAPS models for the utility electric systems on the islands of Oahu, Hawaii and Maui.

HECO Companies Response:

Please see response to ZE-IR-110.

<u>ZE-IR-116</u>

Please produce all documents relating to the load duration curves depicted in Attachment 4 to the *HECO Companies Report on Reliability Standards* filed on February 8, 2010 in this docket, including all documents showing what models and what input assumptions were used to generate such load duration curves.

<u>HECO Companies Response:</u>

The load duration curves were obtained by the instantaneous recorded load data for HELCO and MECO.

For HELCO generation assumptions and source data for the graph, see file "ZER-IR-116 HELCO". No modeling tool was used, other than Excel. The generator assumptions for renewable energy are as follows, and can be viewed on the Data worksheet.

1. Apollo (Tawhiri-Pakini Nui) Average output of 14.06 MW calculated from the average output during non-curtailment periods since installation. Max output of 20.5 MW.
2. HELCO hydro average output of 3.5 MW with maximum output of 4 MW. This utilizes the average output over the last two years, to reflect the effect of plant restoration and repairs in the last couple of years and exclude periods of outage for repairs. These values are in the variable RE category.
3. Waiuku average of 3.055 MW and maximum of 11.5 MW. The average was calculated by recorded average output over the past six years excluding hours of curtailment. These values are in the variable RE category.
4. HRD (Hawi Wind Plant) average of 4.116 MW and maximum of 10.5 MW. This average was calculated by recorded average output excluding periods of likely curtailment. These values are in the variable RE category.

5. PGV represented as 30 MW for the present generation mix.
6. Hill 6 shown in the must-run minimum as 15 MW.
7. Hill 5 shown in the must-run minimum as 8 MW.
8. Puna shown in the must-run minimum as 8 MW.
9. HEP shown in the must-run minimum as 9 MW.
10. Keahole Combine Cycle shown in the must-run minimum as 7 MW.
11. Regulating reserve of 9 MW.
12. Future RE includes 24 MW of biomass and 8 MW of additional geothermal, all of which is dispatchable.
13. Outage periods and other atypical operating conditions are not considered.
14. Other than the future generation listed in item 12, no future generation (additional NEM, FIT, etc…) is included.

For Maui, generation assumptions and source data for the graph, see file "ZE-IR-116 Maui". No modeling tool was used, other than Excel. The input assumptions were as follows:

1. Makila Hydro – a 500 kW hydro with which MECO has a Purchase Power Agreement (PPA) was ignored.
2. Outage periods and other atypical operating conditions are not considered.
3. Other than the two additional wind farms in the future generation scenarios, no future as available renewable generation (additional NEM, FIT, etc…) is accounted for.
4. For the present generation mix scenarios, a minimum of MECO generation of 68 MW + 6 MW of regulating reserve down, and 8 MW of HC&S generation was assumed. This sums to 82 MW of firm generation.

5. These numbers are typical of the MECO minimum loading during times when curtailment typically occurs for excess energy on the Maui grid. To this was added KWP (30 MW wind farm) generation. For the average variable case, KWP was estimated to be at 12.4 MW based on historical capacity factors for a total firm + variable generation of 94.4 MW. For the maximum variable case, KWP was assumed to be at 30 MW for a total firm + variable generation of 112 MW.
6. For the future generation mix scenarios, two additional windfarms were added to the Maui grid bringing the combined wind up to 72 MW. Curtailment is expected to extend to the majority of the hours in a day, so the MECO minimum generation was increased by adding additional units as necessary to maintain MECO regulating reserve requirement of 0.5 MW of regulating reserve up for each MW of wind for the first 30 MW of wind and 1 MW of regulating reserve up for each additional MW of wind. The minimum MECO generation was also increased by the addition of units K1 and K2 at their minimum output (2.5 MW each) because these units typically operate during the day. HC&S generation was increased to 12 MW, consistent with their PPA. The amount of MECO generation is now dependant on the wind power on the system.

   For the average variable case, the same historical capacity factor used in the present generation scenario was used, but for 72 MW of total wind, yielding a variable generation of 29.7 MW. Total generation during this time equals the 68 MW of MECO minimum plus 6 MW regulating reserve down, 5MW from K1 and K2, 12 MW from HC&S, and 29.7 MW of wind, which sums to 120.7 MW.

   For the max variable case, MECO units were added in an attempt to meet the regulating reserve up requirement explained above in order to accommodate all 72 MW of wind. It was not possible to accommodate all 72 MW of wind and the exercise was ended when the generation reached 209 MW, exceeding the highest load of 2009.